

AD-A063 239 CONSTRUCTION ENGINEERING RESEARCH LAB (ARMY) CHAMPAI--ETC F/6 21/4  
FUELS: STATE OF THE ART IN INDUSTRIAL UTILIZATION. (U)  
NOV 78 P KONG, M LEE, S MATHAWAY MIPR-N00025-4-1041  
UNCLASSIFIED CERL-TR-E-135 NL

1 OF 2  
AD  
A063239



ADA063239

construction  
engineering  
research  
laboratory

11  
NW

TECHNICAL REPORT E-135

11 November 1978

DDC FILE COPY.

6 FUELS: STATE OF THE ART IN INDUSTRIAL UTILIZATION  
**LEVEL** 9 Final report

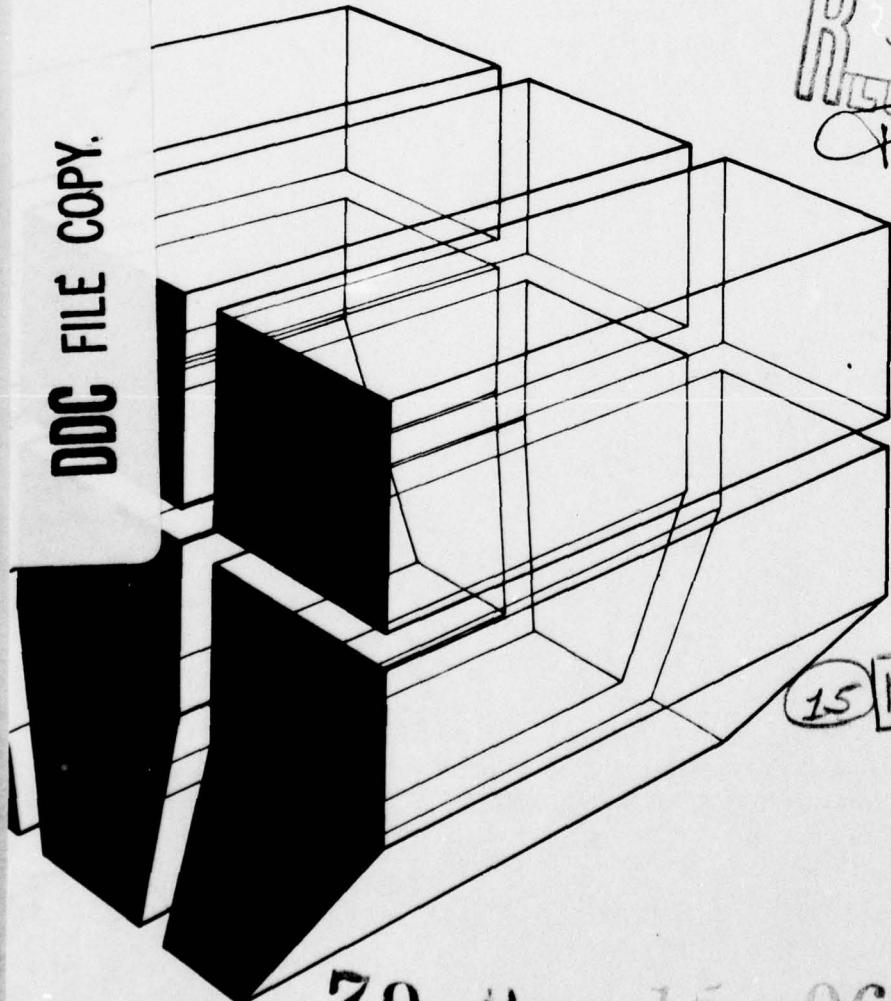
D D C  
RECORDED  
JAN 15 1979  
F C

12 146 p.

10 by  
P. Kong,  
M. Lee  
S. Hathaway

14 CERL-TR-E-135

15 MIPR-N00025-4-1041



79 01 15 061

405 279

WW  
CERL

JTB

Approved for public release; distribution unlimited.

The contents of this report are not to be used for advertising, publication, or promotional purposes. Citation of trade names does not constitute an official indorsement or approval of the use of such commercial products. The findings of this report are not to be construed as an official Department of the Army position, unless so designated by other authorized documents.

***DESTROY THIS REPORT WHEN IT IS NO LONGER NEEDED  
DO NOT RETURN IT TO THE ORIGINATOR***

## SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER CERL-TR-E-135	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) FUELS: STATE OF THE ART IN INDUSTRIAL UTILIZATION		5. TYPE OF REPORT & PERIOD COVERED FINAL
		6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) P. Kong M. Lee S. Hathaway	8. CONTRACT OR GRANT NUMBER(s)	
9. PERFORMING ORGANIZATION NAME AND ADDRESS CONSTRUCTION ENGINEERING RESEARCH LABORATORY P.O. Box 4005 Champaign, IL 61820		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS MIPR NO. N00025-4-1041
11. CONTROLLING OFFICE NAME AND ADDRESS NAVAL FACILITIES ENGINEERING COMMAND 200 Stovall St Alexandria, VA 22332		12. REPORT DATE November 1978
14. MONITORING AGENCY NAME & ADDRESS(if different from Controlling Office)		13. NUMBER OF PAGES 143
		15. SECURITY CLASS. (of this report) Unclassified
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE
16. DISTRIBUTION STATEMENT (of this Report)  Approved for public release; distribution unlimited.		
17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)		
18. SUPPLEMENTARY NOTES Copies are obtainable from National Technical Information Service Springfield, VA 22151		
19. KEY WORDS (Continue on reverse side if necessary and identify by block number) coal converting refuse to energy coal gasification		
20. ABSTRACT (Continue on reverse side if necessary and identify by block number)  This study reviews the state of the art of industrial-scale boiler fuel use for supervisory personnel. Fuels considered were coal, petroleum fuel oil, and refuse.  The sections on coal and oil deal with the basics of selection, equipment and technology for handling and storage, and equipment and technology of combustion. In addition, coal gasification processes are discussed. <i>Zover</i>		

Block 20 continued.

The section on refuse discusses the technology of converting refuse to energy (CRE). It describes in detail current major package CRE systems and considerations for co-firing refuse in boilers currently designed for firing coal.

UNCLASSIFIED

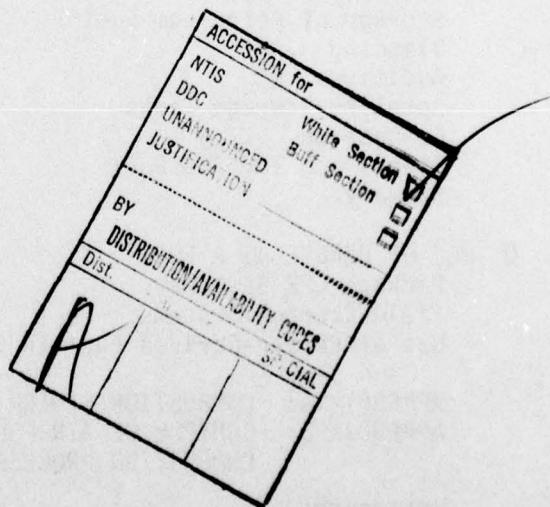
SECURITY CLASSIFICATION OF THIS PAGE(When Data Entered)

## FOREWORD

This research was performed by the U.S. Army Construction Engineering Research Laboratory (CERL) for the U.S. Naval Facilities Engineering Command (NAVFAC) under MIPR No. N00025-4-1041, dated 21 May 1974. The NAVFAC Project Monitor was Mr. R. Thompson. Administrative support provided by Mr. R. G. Donaghy, Chief of the Energy and Habitability Division, is acknowledged.

The authors wish to express their appreciation to Mr. John Woodyard, and Dr. D. Leverenz, CERL, for contributions to various sections of this report; Mr. L. Barry, University of Illinois, for assistance in editing the initial draft; and Dr. J. Stukel, University of Illinois, for reviewing the first draft.

COL J. E. Hays is Commander and Director of CERL, and Dr. L. R. Shaffer is Technical Director.



79 01 15 061

## CONTENTS

	<u>Page</u>
DD Form 1473	
FOREWORD	3
LIST OF TABLES AND FIGURES	5
1 INTRODUCTION . . . . .	9
Background	
Objective	
Approach	
Scope	
2 COAL . . . . .	10
Coal Classification	
Composition of Coal	
Physical Properties of Coal	
Commercial Sizes of Coal	
Sampling	
Handling	
Direct Use of Coal	
Coal Gasification	
3 PETROLEUM FUELS . . . . .	70
Characteristics of Fuel Oil	
Transportation	
Storage of Petroleum Fuel	
Blending	
Additives	
Sampling Storage Tanks	
Combustion	
Diesel and Turbine Fuel	
Summary	
4 USE OF REFUSE AS A FUEL . . . . .	102
Package CRE Systems	
Field-Erected Systems	
Use of Refuse-Derived Fuel in Existing Boilers	
APPENDIX A: COMBUSTION STOICHIOMETRY	129
APPENDIX B: CONTROL OF AIR POLLUTANTS FROM COMBUSTION PROCESSES	132
REFERENCES	
DISTRIBUTION	141

## TABLES

<u>Number</u>		<u>Page</u>
1	Classification of Coals by Rank	11
2	Principal Ranks of Coal Mined in Various States	13
3	Representative Proximate Analyses and Heating Values of Various Ranks of United States Coals (Ash-Free Basis)	14
4	Comparison of Bases for Coal Analyses; High-Volatile A Bituminous Coal, Allegheny County, Pa., Pittsburgh Bed	16
5	ASTM Standards Relating to the Specifications and Methods of Testing for Coal	17
6	Grindability of Some Typical Coals of the United States	23
7	Standard Anthracite Coal Sizes	25
8	Typical Railroad Car Dimensions and Capacities	28
9	Feeder Selection Based on Physical Characteristics	34
10	Conveyor Selection Based on Function Desired	35
11	Nominal Characteristics and Uses of Industrial Stokers	48
12	Types of Pulverizers for Various Coals and Coke	53
13	Coal Gasification Processes (High-Btu Gas)	61
14	Coal Gasification Processes (Low- and Medium-Btu Gas)	67
15	Detailed Requirements for Fuel Oils	71
16	Selected ASTM Standards Relating to the Specifications and Testing Methods for Petroleum Fuels	72
17	Volume Correction Table for Fuel Oils	78
18	Specific Heat of Fuel Oils	83

TABLES (Cont'd)

<u>Number</u>		<u>Page</u>
19	Commercial Oil Burners	91
20	Detailed Requirements for Diesel Fuel Oils	95
21	Detailed Requirements for Gas Turbine Fuel Oils	96
22	A Summary of Current Refuse Firing Systems	120
A1	Theoretical Air for Combustion	130

FIGURES

1	Average Sulfur Content of Coal Deposits in the Conterminous United States (Percent)	19
2	Estimated Remaining Coal Reserves in the United States of All Ranks, by Sulfur Content, as of January 1, 1965	20
3	Diagram Showing Overall Operation of Coal-Handling System	27
4	Typical Railroad Clearances for Straight Track	29
5	Car Shaker	30
6	Rotary Car Dumper	31
7	Flight Feeder	32
8	Screw Feeder	32
9	Bucket-Elevator Types and Bucket Details	33
10	Cross Section of Correct and Incorrect Storage Piles	37
11	Combustion Zones in an Overfeed Fuel Bed	40
12	Traveling-Grate Stoker with Rear Firing Arch	41

FIGURES (Cont'd)

<u>Number</u>		<u>Page</u>
13	Spreader Stoker	43
14	Cross-Sectional View of a Single-Retort Underfeed Stoker	45
15	A Multiple-Retort Underfeed Stoker	46
16	The Influence of Grindability, Moisture Content, and Fineness of Grind on Pulverizer Capacity	51
17	Burner and Furnace Configurations for Pulverized-Coal Firing	56
18	Pressurized Fluidized-Bed Combustor	59
19	Lurgi Gasifier	63
20	Koppers-Totzek Process	64
21	Winkler Gasifier	65
22	Nomograph for Determining Vertical Cylindrical Tank Capacity	85
23	Principal Types of Oil Burners	92
24	Principles of Atomization Employed in Steam and Air Atomizing Nozzles	93
25	Rotary-Kiln Incinerator	107
26	Starved-Air Incinerator (First Major Configuration)	109
27	Basket-Grate Incinerator	111
28	Augered-Bed Incinerator	113

## FUELS: STATE OF THE ART IN INDUSTRIAL UTILIZATION

### 1 INTRODUCTION

#### Background

This study was conducted at the request of the Naval Facilities Engineering Command to provide engineering and technical assistance for clarifying and modernizing guidance on fuel use at Naval shore installations.

#### Objective

The objective of this study was to review and determine the state of the art of fuel use in industrial-scale boilers ranging in capacity between 5 MBtu/hr (1.5 Mwt) and 200 MBtu/hr (60 Mwt).

#### Approach

The state of the art of industrial-scale fuel use was determined through review of DOD and Navy fuels policy documents, available commercial hardware, and Federal and industrial research and development efforts.

#### Scope

This support provides information for supervisory and decision-making personnel to support assessments of efficient fuel use at Naval shore installations. Chapter 2 furnishes a discussion of technologies for the direct combustion and gasification of coal, with consideration also given to coal classification, properties, sampling procedures, and handling and storage. Chapter 3 furnishes a discussion of technologies for using petroleum as a fuel for boilers and diesel and turbine engines; consideration is also given to fuel oil characteristics, transportation, storage, blending, additives, and sampling for quality control. The use of solid waste as a primary fuel (heat-recovery incineration) and as a supplementary refuse-derived fuel (RDF) for use in existing boilers is treated in Chapter 4. Conceptual discussions on combustion stoichiometry and control of combustion-generated air pollutants are furnished in Appendices A and B, respectively. Use of natural gas is not treated in this report, because of its increasing scarcity and probable unavailability as a primary fuel in industrial-scale military boilers.

## 2 COAL

### Coal Classification

Coal classification provides useful data for selecting burning and handling equipment and for designing other power plant components. Coal can be classified by numerous specific chemical and physical properties. The American National Standards classification method, developed by the American Society for Testing and Materials (ASTM),\* ranks coal according to its degree of metamorphism from lignite to anthracite (Table 1). The bases of this system are moist, mineral-matter-free (m.m.f.) heating value for the lower-ranked coals and the dry m.m.f. fixed carbon value for the higher-ranked coals (see ASTM D388).\*\* The Parr formulas (Eqs 1, 2, and 3), or the approximation formulas (Eqs 4 and 5) are used to calculate these quantities.

$$\text{moist m.m.f. calorific value } Q' = \frac{100(Q-50S)}{100 - (1.08A+0.55S)} \quad [\text{Eq 1}]$$

$$\text{dry m.m.f. fixed carbon, } F' = \frac{100(F-0.15S)}{100 - (M+1.08A+0.55S)} \quad [\text{Eq 2}]$$

$$\text{dry m.m.f. volatile matter, } V' = 100 - F' \quad [\text{Eq 3}]$$

$$Q' = \frac{100Q}{100 - (1.1A+0.1S)} \quad [\text{Eq 4}]$$

$$F' = \frac{100F}{100 - (M+1.1A+0.1S)} \quad [\text{Eq 5}]$$

where M is the weight percentage of moisture;

F, A, and S are the respective weight percentages, on a moist basis of fixed carbon, ash, and sulfur;

Q is the calorific value, Btu/lb (1 Btu/lb = 2.326 kJ/kg), on a moist non-m.m.f. basis

\*Other classification systems are the International Classification of Hard Coals by type, and the International Classification of Brown Coals.

\*\*Information inside parentheses denotes the ASTM designation number.

A listing of pertinent ASTM specifications is given in Table 5 for coal and in Table 16 for petroleum fuels.

Table 1

(From "Standard Specification for Classification of Coals by Rank,"<sup>a</sup> 1975 Annual Book of ASTM Standards, ASTM D388-66, Part 26 [American Society for Testing and Materials, 1975], p 215. Reprinted by permission of the American Society for Testing and Materials, copyright.)

Class	Group	Fixed Carbon Limits, percent (Dry, Mineral- Matter-Free Basis)		Volatile Matter Limits, percent (Dry, Mineral- Matter-Free Basis)		Calorific Value Limits, Btu per pound (Moist, Mineral-Matter- Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Less Than	Equal or Greater Than	Less Than	
I. Anthracitic	1. Meta-anthracite	98	--	--	2	--	--	nonagglomerating
	2. Anthracite	92	98	2	8	14	--	
	3. Semianthracite	86	92	8	--	--	--	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	--	--	Commonly agglomerating <sup>e</sup>
	2. Medium volatile bituminous coal	69	78	22	31	--	--	
	3. High volatile A bituminous coal	--	69	31	--	14 000 <sup>d</sup>	---	
	4. High volatile B bituminous coal	--	--	--	--	13 000 <sup>d</sup>	14 000	
	5. High volatile C bituminous coal	--	--	--	--	11 500	13 000	
III. Subbituminous	1. Subbituminous A coal	--	--	--	--	10 500	11 500	nonagglomerating
	2. Subbituminous B coal	--	--	--	--	9 500	10 500	
	3. Subbituminous C coal	--	--	--	--	8 300	9 500	
IV. Lignitic	1. Lignite A	--	--	--	--	6 300	8 300	nonagglomerating
	2. Lignite B	--	--	--	--	--	6 300	

<sup>a</sup> This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48 percent dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free British thermal units per pound.

<sup>b</sup> Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

<sup>c</sup> If agglomerating, classify in low-volatile group of the bituminous class.

<sup>d</sup> Coals having 69 percent or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

<sup>e</sup> It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

\* 1 Btu/lb = 2.326 kJ/kg.

A coal's *agglomerating character* classifies it into various groups. Coals are considered agglomerating if the coke button remaining from the test for volatile matter (see ASTM D 3175) will support a 500-g weight, or if the button shows swelling or porous cell structure.

Table 2 outlines the principal ranks of coal mined in the major U.S. coal-producing states.

### Composition of Coal

Coal composition is generally determined either by proximate analysis or ultimate analysis.

#### *Proximate Analysis*

The *proximate analysis* (ASTM D 3172) determines by standardized tests the amount of moisture, volatile matter, fixed carbon, and ash in coal. Table 3 provides the proximate analyses and heating values, on an ash-free basis, of coals representing the various ranks.

*Moisture* may consist of (1) surface or extraneous moisture from external sources such as conditions in the mine or the weather during transit, and (2) inherent or bed moisture which is held in the coal's pores. Information about moisture content is useful for designing and selecting coal-handling and coal-preparation equipment such as pulverizers (high surface moisture reduces pulverizer capacity).

*Volatile matter* is the product liberated as gases and vapors when coal is heated under prescribed conditions. Since the quantity of volatile matter indicates the amount of gaseous fuel present, it affects the mechanics of firing and influences both furnace volume and the arrangement of heating surfaces.

*Fixed carbon* is the residue left after the volatile matter is driven off; its value is calculated when the percentages of moisture, volatile matter, and ash of the proximate analysis are subtracted from 100. This residue contains carbon and a small amount of hydrogen and oxygen, 0.4 to 1.0 percent nitrogen, and approximately half the sulfur originally contained in the coal.

*Ash* is the inorganic residue remaining after the coal has been combusted under specified conditions. It is composed mostly of compounds of silicon, aluminum, iron, and calcium, and contains small amounts of compounds of magnesium, sodium, potassium, and titanium. The material comprising ash may be quite different from the original mineral matter.

#### *Ultimate Analysis*

The *ultimate analysis* (ASTM D3176) determines by prescribed methods the amount of ash, carbon, hydrogen, nitrogen, oxygen, and sulfur in

Table 2  
Principal Ranks of Coal Mined in Various States\*

State	Anthracite	Semianthracite	Low-volatile bituminous	Medium-volatile bituminous	High-volatile A bituminous	High-volatile B bituminous	High-volatile C bituminous	Subbituminous A	Subbituminous B	Subbituminous C	Lignite
Alabama			x	x							
Alaska					x	x	x	x	x	x	x
Arkansas	x	x	x	x							x
Colorado				x	x	x	x	x	x	x	x
Illinois				x	x	x	x	x	x	x	x
Indiana					x	x					
Iowa						x					
Kansas					x	x					
Kentucky:											
Eastern					x	x					
Western					x	x	x				
Maryland		x	x	x							
Missouri						x					
Montana					x	x	x	x	x	x	x
New Mexico					x	x	x	x	x	x	x
North Dakota					x	x	x	x	x		x
Ohio					x	x	x				
Oklahoma			x	x	x	x	x				
Pennsylvania	x	x	x	x	x	x	x				
South Dakota											x
Tennessee				x	x						
Texas							x	x			x
Utah					x	x	x	x	x		
Virginia	x	x	x	x							
Washington					x	x	x	x			x
West Virginia	x	x	x					x	x	x	
Wyoming					x	x	x	x	x	x	

\* Compiled by *Chemical Engineers Handbook* largely from *Typical Analyses of Coal of the United States*, U.S. Bureau of Mines Bulletin 446, and *Coal Reserves of the United States*, U.S. Geological Survey Bulletin 1136.

Table 3

Representative Proximate Analyses and Heating Values  
of Various Ranks of United States Coals  
(Ash-Free Basis)

(From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 9-4. Copyright by McGraw-Hill.)

Rank		Moisture, %	Fixed carbon, %	Volatile matter, %	Calorific value, Btu/lb*
	Meta-anthracite	16.3	80.5	3.2	11,480
	Anthracite	4.8	89.6	5.6	14,250
	Semianthracite	2.8	85.7	11.5	15,010
	Low-volatile bituminous	3.1	78.2	18.7	15,220
	Medium-volatile bituminous	2.2	71.8	26.0	15,240
	High-volatile A bituminous	2.4	59.1	38.5	14,810
	High-volatile B bituminous	9.5	49.7	40.5	13,090
	High-volatile C bituminous	15.9	44.9	39.2	11,960
	Subbituminous A	17.5	46.4	36.1	11,050
	Subbituminous B	23.2	42.1	34.7	10,040
	Subbituminous C	26.9	40.5	32.6	9,180
	Lignite	39.1	31.4	29.5	7,440

\* 1 Btu/lb = 2.326 kJ/kg.

coal. The *heating value*--the heat produced at constant volume by the complete combustion of a unit quantity of coal in an oxygen-bomb calorimeter under specified conditions, and expressed as Btu/lb--can be determined approximately with these analyses. The final calculated value, which includes the latent heat of vaporization of water in the combustion products, is called the gross heating or high heating value,  $Q_h$ . Generally, the low heating value,  $Q_l$ , which assumes that all products of combustion remain in the gaseous state, is needed for combustion calculations and is obtained from

$$Q_l = Q_h - 92.7H \quad [\text{Eq } 6]$$

$Q_h$  in Btu/lb can be approximated by the Dulong formula,

$$Q_h = 145.44C + 620(H-0/8) + 41S \quad [\text{Eq } 7]$$

where C, H, ), and S are the weight percentages of carbon, total hydrogen, oxygen, and sulfur, respectively. This formula has an average deviation of only 2 percent for coals containing up to 10 percent oxygen on the dry, ash-free basis.

Coal analyses are reported on several bases. The *as-received* basis represents the weight percentage of each constituent in the sample as it is received in the plant. The *moisture-free* (dry) basis is generally the most useful, since performance calculations can be corrected easily for actual moisture content when they are used (see ASTM D3180). The dry, *ash-free* basis is frequently used to approximate a coal's rank and source, since the heating value of like coals is remarkably constant when calculated on this basis. Table 4 illustrates the use of these bases.

Detailed laboratory procedures for proximate and ultimate analyses are given in ASTM D3172 and D3176, respectively. Table 5 tabulates the ASTM Standards relating to coal specifications and testing methods.<sup>1</sup>

#### *Sulfur in Coal*

Efforts to abate atmospheric pollution are concerned with the sulfur content of coal, since its combustion discharges sulfur oxides into the atmosphere. Sulfur in coal occurs in three forms: pyrites ( $\text{FeS}_2$ ); organic sulfur; and sulfate sulfur. Pyritic sulfur can be partially removed with standard coal-washing equipment; the amount removed depends on the coal's size and on the size and distribution of the pyrite particles. Organic sulfur may comprise 20 to 80 percent of the coal's total sulfur, and since its chemical bonding to the coal

<sup>1</sup>1975 Annual Book of ASTM Standards, Part 26 (American Society for Testing and Materials [ASTM], 1975).

Table 4

Comparison of Bases for Coal Analyses; High-Volatile A Bituminous Coal,  
 Allegheny County, Pa., Pittsburgh Bed  
 (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*,  
 5th ed. [McGraw-Hill, 1973], p 9-4. Copyright by McGraw-Hill.)

Basis	Proximate weight %			Ultimate weight %*				Heating Value,** Btu/lb	
	Moisture	Volatile matter	Fixed carbon	Ash	Carbon	Hydrogen	Oxygen		
As-received	2.4	36.6	53.2	7.8	75.8	5.1	8.2	1.5	1.6
Dry	---	37.5	54.5	8.0	77.7	5.0	6.2	1.5	1.6
Dry, ash-free	---	40.8	59.2	---	84.4	5.4	6.7	1.7	1.8

\* On the as-received basis, the hydrogen and oxygen include the hydrogen and oxygen of the moisture.

\*\* 1 Btu/lb = 2.326 kJ/kg.

Table 5  
ASTM Standards Relating to the Specifications  
and Methods of Testing for Coal

---

**Specifications for:**

\*D 388-66(1972) \*\* Classification of Coals by Rank

**Methods of Test for:**

D2795-69(1974)	Analysis of Coal and Coke Ash
D3174-73	Ash in the Analysis Sample of Coal and Coke
D3180-74	Calculating Coal and Coke Analyses from As- Determined to Different Bases
D3178-73	Carbon and Hydrogen in the Analysis Sample of Coal and Coke
*D1756-62(1974)	Carbon Dioxide in Coal
*D2361-66(1972)	Chlorine in Coal
*D2234-72	Collection of a Gross Sample of Coal
*D 291-60(1975)	Cubic Foot Weight of Crushed Bituminous Coal
D2798-72	Microscopical Determination of the Reflectance of the Organic Components in a Polished Specimen of Coal
D 440-49(1969)	Drop Shatter Test for Coal
*D 547-41(1975)	Dustiness of Coal and Coke, Index of
*D1857-68(1974)	Fusibility of Coal Ash
*D1412-74	Equilibrium Moisture of Coal at 96 to 97 Percent Relative Humidity and 30 C
*D2014-71	Expansion or Contraction of Coal by the Sole- Heated Oven
*D 720-67(1972)	Free-Swelling Index of Coal
D 409-71	Grindability of Coal by the Hardgrove-Machine Method
*D2015-66(1972)	Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter
D3286-73	Gross Calorific Value of Solid Fuel by the Iso- thermal-Jacket Bomb Calorimeter
D2961-74	Moisture in Coal, Total Limited Purpose
D2799-72	Microscopical Determination of Volume Percent of Physical Components of Coal
D3173-73	Moisture in the Analysis Sample of Coal and Coke
D3179-73	Nitrogen in the Analysis Sample of Coal and Coke
D1812-69(1974)	Plastic Properties of Coal by the Gieseler Plastometer

Table 5 (Cont.)

D2639-74	Plastic Properties of Coal by the Constant-Torque Giesler Plastometer
D2797-72	Preparing Coal Samples for Microscopical Analysis by Reflected Light
D3172-73	Proximate Analysis of Coal and Coke
D 197-30(1971)	Sampling and Fineness Test of Pulverized Coal
*D 271-70	Sampling and Analysis, Laboratory, of Coal and Coke
*D2013-72	Samples, Coal, Preparing for Analysis
*D 410-38(1969)	Sieve Analysis of Coal
D 311-30(1969)	Sieve Analysis of Crushed Bituminous Coal
D 310-69(1975)	Size of Anthracite
*D 431-44(1969)	Size of Coal, Designated from Its Sieve Analysis
*D1757-62(1974)	Sulfur in Coal Ash
D2492-68(1974)	Sulfur, Forms of, in Coal
D2961-74	Total Moisture in Coal Reduced to Number 8 Top Sieve Size (Limited Purpose Method)
D3177-75	Total Sulfur in the Analysis Sample of Coal and Coke
D 441-45(1975)	Tumbler Test for Coal
D3176-74	Ultimate Analysis of Coal and Coke
D3175-73	Volatile Matter in the Analysis Sample of Coal and Coke

Definitions of Terms Relating to:

*D 121-72	Coal and Coke
*D 407-44(1969)	Gross Calorific Value and Net Calorific Value of Solid and Liquid Fuels
D2796-72	Lithologic Classes and Physical Components of Coal

---

\* Approved as American National Standard by the American National Standards Institute.

\*\* D 388 is the ASTM standard number, 66 is the year the standard originally was issued, and the number inside parentheses denotes the year the standard was reapproved without change.

substance is complex, extreme measures are necessary to break the chemical bonds. As of 1975 there was no economical method of removing organic sulfur. Sulfate sulfur comprises a maximum of only a few hundredths of one percent of the coal and therefore is not of major concern.

The sulfur content of coals mined in the United States varies widely, ranging from 0.2 to 7 percent by weight, on a dry basis. (Extensive data on the forms of sulfur in United States coals are given in U.S. Bureau of Mines Information Circular 8301<sup>2</sup>.) Figure 1 illustrates the average sulfur content of U.S. coal deposits, and Figure 2 shows the estimated remaining coal reserves of all ranks, by sulfur content.

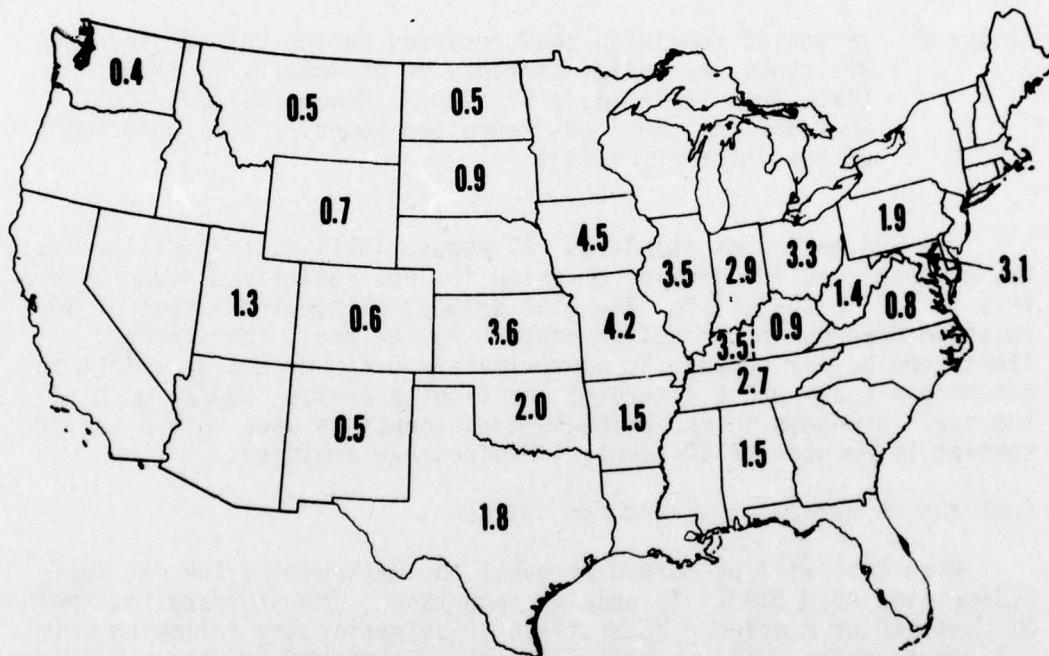


Figure 1. Average sulfur content of coal deposits in the conterminous United States (percent). (From J. Calvin Giddings, "Average Sulfur Content of U.S. Coal Deposits," *Chemistry, Man and Environmental Change*, Fig. 7-12, [Harper & Row, 1973], p 262.)

<sup>2</sup>"Forms of Sulfur in U.S. Coals," U.S. Bureau of Mines Information Circular 8301 (1966).

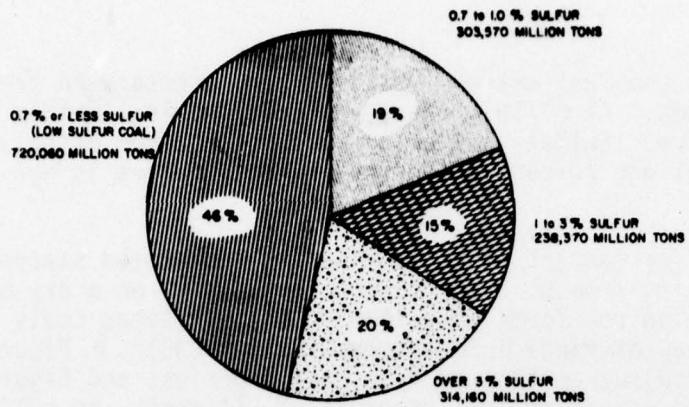


Figure 2. Estimated remaining coal reserves in the United States of all ranks, by sulfur content, as of January 1, 1965.  
 (Data from Table 24, p 52 of *U.S. Energy Outlook--Coal Availability* [National Petroleum Council, U.S. Department of the Interior, 1973]).

The EPA emissions standards (17 August 1971) state that the maximum allowable sulfur dioxide emission for new coal-fired steam generators is 1.2 lb SO<sub>2</sub>/million Btu (.52 kg/GJ). Since the amount of SO<sub>2</sub> emission depends on the sulfur content in the fuel, the standard limits the sulfur content to approximately 0.8\* percent by weight for bituminous coals and 0.4 percent for lignite coals. Hence, much of the coal produced in the United States cannot be used unless sulfur content is reduced or SO<sub>2</sub> control devices are employed.

#### *Coal Ash Characteristics and Composition*

When coal will be burned or gasified, determining the *ash fusibility* (see ASTM D1857) is usually important. The standard test method consists of heating a cone of ash to determine the following critical temperatures: (1) initial deformation temperature--the temperature at which the first rounding of the apex occurs; (2) softening and hemispherical temperatures--the temperatures at which the height of the cone is equal to the width and one-half the width, respectively, of the base; and (3) fluid temperature--the temperature at which the fused mass has spread out in a nearly flat layer with a maximum height of 1/16 in. (1.6 mm). The softening temperature is usually a rough

\*The amount of SO<sub>2</sub> emitted can be calculated from the sulfur content and heating value of fuel by the formula:

$$1\text{b SO}_2/\text{million Btu} = 0.198 \times (\text{percent sulfur}) \times 10^6 \div (\text{heating value of fuel, Btu/lb}).$$

qualitative guide of the tendency of ash to form large masses of sintered or fused ash, which impair heat transfer and impede gas flow. Likewise, fluid temperature and fluid interval (the temperature difference between softening and fluid temperatures) are qualitative guides to the "flow" characteristics of ash in a slag-tap furnace. However, since ash fusibility is not an infallible index, care must be taken when using these data for designing and operating purposes.<sup>3</sup>

Calculated as oxides, the composition of coal ash (percent by weight) varies as follows:

Silica, SiO <sub>2</sub>	20 to 60 percent
Alumina, Al <sub>2</sub> O <sub>3</sub>	10 to 35 percent
Ferric Oxide, Fe <sub>2</sub> O <sub>3</sub>	5 to 35 percent
Calcium Oxide, CaO	1 to 20 percent
Magnesium Oxide, MgO	0.3 to 4 percent
Titanium Oxide, TiO <sub>2</sub>	0.5 to 2.5 percent
Alkalies, Na <sub>2</sub> O and K <sub>2</sub> O	1 to 4 percent
Sulfur Trioxide, SO <sub>3</sub>	0.1 to 12 percent

Knowing the composition of coal ash is useful for estimating slagging and clinkering in fuel beds; predicting the flow properties of coal-ash slag<sup>4</sup> in slag-tap and cyclone furnaces; and predicting, to a limited extent, the fouling and corrosion of heat-exchange surfaces in pulverized-coal-fired furnaces.

#### Physical Properties of Coal

The free-swelling index measures a coal's tendency to swell when burned or gasified in a fixed or fluidized bed; coals having a high free-swelling index will generally cause difficulties (see ASTM D 720 for test details).

The grindability index--the ease (or difficulty) of grinding coal--is complexly related to physical properties such as hardness, fracture, and tensile strength. The Hardgrove (see ASTM D409) machine is usually used to determine the relative grindability or ease of

<sup>3</sup>Steam--Its Generation and Use, 38th ed. (The Babcock and Wilcox Co., 1972).

<sup>4</sup>R. Corey, "Measurements and Significance of the Flow Properties of Coal Ash Slag," U.S. Bureau of Mines Bulletin 618 (1964).

pulverizing a coal in comparison to that of a standard coal chosen as having a grindability of 100. In general, coals having the highest grindability index (i.e., are easiest to grind) are those having approximately 14 to 30 percent volatile matter on a dry, ash-free basis. Coals having either lower or higher amounts of volatile matter are usually more difficult to grind. Table 6 lists the grindability index of some typical U.S. coals.

The bulk density of broken coal varies according to the coal's specific gravity, size distribution, and moisture content, and the amount of settling occurring when the coal is piled. Following are some useful approximations of the bulk density of various ranks of coal:

	<u>lb/cu ft (kg/m<sup>3</sup>)</u>
Anthracite	50 to 58 (800 to 930)
Bituminous	42 to 57 (670 to 915)
Lignite	40 to 54 (640 to 865)

Size stability--a coal's ability to withstand breakage during handling and shipping--is determined by dropping a 50-lb (23-kg) sample of coal two times from a height of 6 ft (1.8 m) onto a steel plate. By analyzing the sizes of coal pieces before and after the test, the size stability can be reported as a percentage factor (ASTM D440). The friability test for measuring a coal's tendency to break during repeated handling is determined by the standard tumbler test (ASTM D441).

Spiers' *Technical Data on Fuels*<sup>5</sup> gives the specific heat of dry, ash-free coal as follows:

	<u>Btu/lb°F (kJ/kg°C)</u>
Anthracite	0.22 to 0.23 (.92 to .96)
Bituminous	0.24 to 0.26 (1.00 to 1.09)

The relationship between specific heat and water content, and between specific heat and ash content, is linear. The specific heat on a dry, ash-free basis can be corrected to the as-received basis.\*

<sup>5</sup>H. M. Spiers, ed., *Technical Data on Fuel*, 5th ed., The British National Committee World Power Conference (1950), p 168.

\*For example, bituminous coal having 5 percent moisture and 6 percent ash (specific heat = 0.165), would have a specific heat of  $[0.24 \times 89 + 1 \times 5 + 0.165 \times 6]/100 = 0.273$  Btu/lb°F.

Table 6

(From C. Carmichael, ed., Kent's Mechanical Engineers Handbook, Design and Production Volume, 12th ed. [John Wiley and Sons, Inc., 1969], p 7-13. Reprinted by permission of John Wiley and Sons, Inc.)

State	County	Bed	Source	Proximate analysis, moisture-free basis, percent				Grind- ability index
				Size, in.**	Volatile matter	Fixed Carbon	Ash	
Pennsylvania	Clinton	Lower Kittanning (B)	R/M	24.2	62.4	13.4	117	
	Somerset	Upper Kittanning (C)	R/M	17.8	70.5	11.7	100	
	Greenbrier	Sewell	1 1/4 x 0	26.5	68.1	5.4	88	
West Virginia	Randolph	Lower Kittanning	2 x 0	28.8	60.7	10.5	78	
West Virginia	McIntosh	Secor	5 x 2 1/2	34.4	55.7	9.9	71	
Ohio	Coshocton	Middle Kittanning	3/4 x 0	37.8	55.4	6.8	66	
Indiana	Vigo	III	1/2 x 0	43.5	46.4	10.1	63	
Illinois	Williamson	No. 5	1 1/2 x 28 mesh	36.1	54.6	9.3	60	
Kansas	Bourbon	Bevier	3/4 x 0	40.2	49.4	10.4	59	
North Dakota	Divide	-----	2 x 1/4	42.5	47.8	9.7	53	
Kentucky	McCreary	No. 2	2 x 0	40.5	46.2	13.3	49	
Pennsylvania	Northumberland	(Anthracite)	No. 4 (Buckwheat)	5.9	85.8	8.3	44	
Utah	Carbon	Castlegate D	1 x 3/16	43.5	50.2	6.3	43	
Alabama	Marion	Black Creek	2 3/4 x 0	39.6	57.7	2.7	37	
Pennsylvania	Luzerne	(Anthracite)	Nut	5.9	87.5	6.6	21	

\* See also Free-swelling and Grindability Indexes of United States Coals, Bureau of Mines Information Circular 8025.

\*\* 1 in. = 25.4 mm

Following is the mean specific heat of coal ash and slag, which is used to calculate heat balances on furnaces, gasifiers, and other coal-consuming systems:

Temperature range, °F (°C)	Mean specific heat Btu/lb°F (kJ/kg°C)	
32 to 100 (0 to 37)	0.212	(.887)
32 to 1500 (0 to 807)	0.224	(.937)
32 to 1900 (0 to 1027)	0.232	(.971)
32 to 200 (0 to 92)	0.235	(.983)
32 to 2500 (0 to 1357)	0.272	(1.138)

#### Commercial Sizes of Coal

Since there are inherent differences in the fracturing characteristics of bituminous coal, the sizes are not standardized. Screening and sizing practices usually are based mainly on local marketing conditions. Bituminous coal sizes are generally expressed by two numerals. The first, larger numeral refers to the size of screen through which the coal was passed, and the second, smaller numeral refers to the size of screen through which the coal would not pass. The following size designations are common: (1) run-of-mine coal, which is shipped from the mine without screening; (2) run-of-mine 8-in. (203-mm) coal, which has had its oversized lumps broken up; (3) 5-in. (127-mm) lump coal that will not pass through a 5-in. (127-mm) round-hole screen; (4) 5-x 2-in. (127-x 50-mm) egg; (5) 2-x 1 1/4-in. (50-x 31.8-mm) nut; (6) 1 1/4 x 3/4-in. (31.8-x 120-mm) stoker; and (7) 3/4-x 0-in. (19.0-x 0-mm) slack. The words "egg" and "nut" are trade names having no fixed meaning; slack coal may mean all the coal that can pass through a given screen size; e.g., the sizes 2-in. (50-mm) slack, 2-in. (60-mm) nut slack, or 2-x 0-in. (50-x 0-mm) slack have the same meaning.

Anthracite coals are sized and named according to the standard shown in Table 7. Standard screen analysis of anthracite coals has been adopted by the ASTM (see ASTM D310).

Names for the sizes of the lower-ranked coals have not been standardized.

#### Sampling

Reliable data about the composition and physical characteristics of coal can be obtained only from samples that adequately represent the bulk lot. ASTM provides standards for properly collecting and preparing

Table 7

Standard Anthracite Coal Sizes  
(From 1975 Annual Book of ASTM Standards, Part 26 [ASTM, 1975],  
p 203. Reprinted by permission of the American Society for  
Testing and Materials, copyright.)

Name	Size of Round-Hole Openings in Testing Screens, in. (mm)			
	Passing		Retained on	
Broken	4 3/8	(111)	3 1/4 to 3	(82 to 76)
Egg	3 1/4 to 3	(82 to 76)	2 7/16	(62)
Stove	2 7/16	(62)	1 5/8	(41.3)
Nut	1 5/8	(41.3)	13/16	(20.6)
Pea	13/16	(20.6)	9/16	(14.3)
Buckwheat	9/16	(14.3)	5/16	(7.9)
Rice	5/16	(7.9)	3/16	(4.8)

*samples for analysis: Collection of a Gross Sample of Coal (ASTM D2234) and Preparing Coal Samples for Analysis (ASTM D2013). Industrial coal samplers, which are usually designed to obtain samples from conveyors or chutes, are usually the plate, belt, or rotary-drum types.*

### Handling

Coal handling is the transportation of coal from the delivery point to storage, and the reclamation from storage and movement to the combustion equipment. Some of the factors considered in the design of a coal-handling system are the plant's capacity, the convenience of its various components, and its flexibility, i.e., the system must be able to handle a wide variety of coals. Figure 3 shows the typical steps of the overall operation. In some systems, not all of the steps are required; e.g., a simple operation would use steps 1c-6-7-9, whereas a more complicated system would employ steps 1a-2-4-6-7-9.

### *Transportation*

Coal usually arrives at the plant by rail, barge, or truck and in some cases by conveyor or pipeline. Rail and truck are the most common methods. The three basic ways to ship coal by rail are bulk rate, which requires a minimum tonnage per train to qualify for special rates; unit trains, which are generally considered by plants consuming at least 150,000 tons/yr (136 000 Mg/yr) of coal; and integral trains, which are generally used by large consumers, such as electric utilities. Table 8 gives the dimensions and capacities of hopper cars used to transport coal. The capacities of trucks depend on state highway load limits, which depend on the net vehicle weight and the number of vehicle axles; the average legal maximum combined weight of vehicle and cargo is 73,000 lb (33 000 kg).

It is important to know the width, length, height, and turning radius of rail and highway vehicles that will serve a facility. These dimensions can be obtained from carriers or from equipment manufacturers. Figure 4 shows a set of typical railroad clearances. In addition, adequate clearances must be provided for railroad and other work crews; these clearances are often specified in state labor-practice codes.

River barges are either 175 x 26 ft (53 x 7.9 m) or 195 x 35 ft (59.4 x 10.7 m). The smaller size, sometimes called the standard or Pittsburgh Standard barge, carries approximately 1000 tons (900 Mg); the larger, or jumbo barge, carries 1500 tons (1360 Mg). Practically all barges currently being used have watertight cargo space, and most have open tops. Covered barges are generally not used, because they are more difficult to load and unload and because many docks cannot accept them.

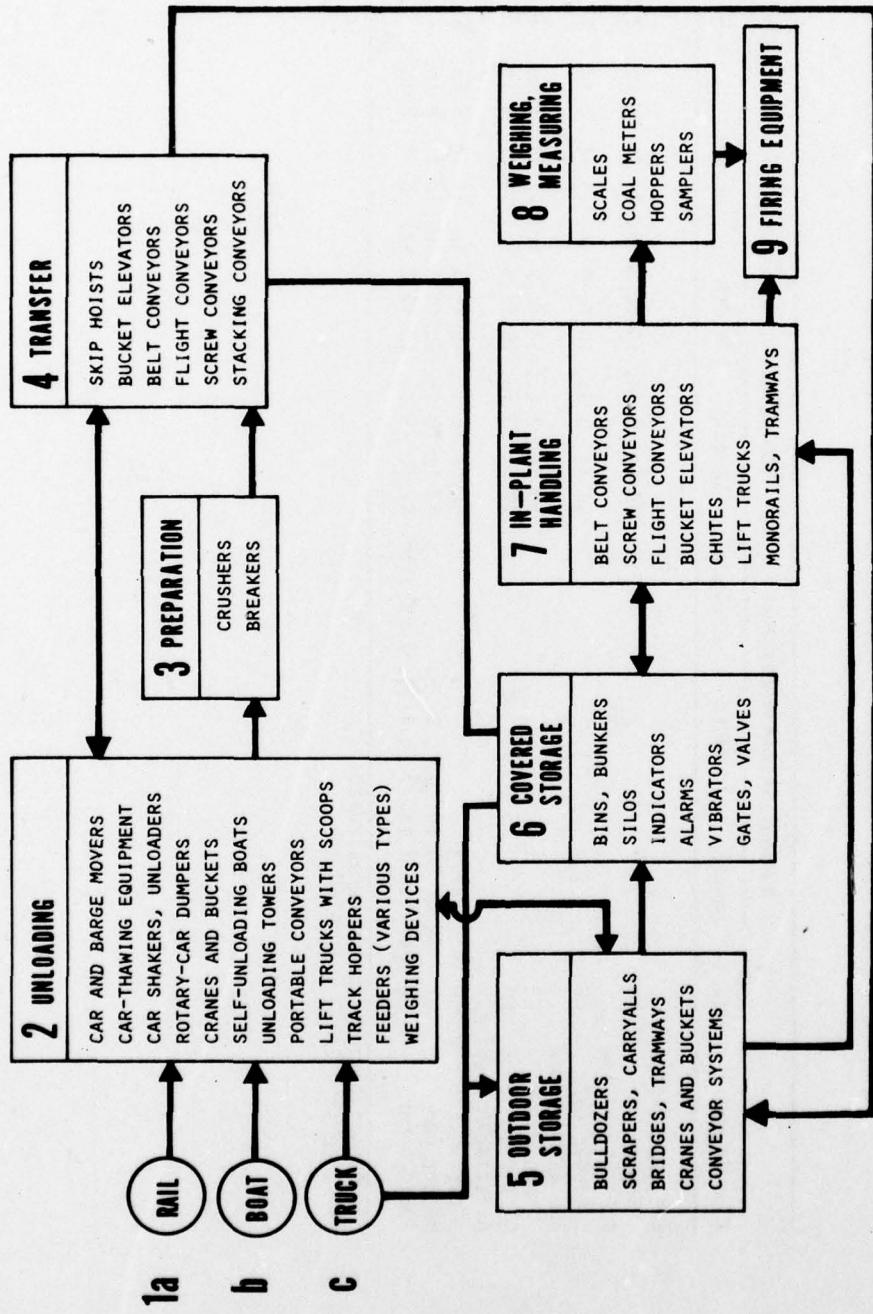


Figure 3. Diagram showing overall operation of coal-handling system.  
 (From "Power From Coal--Part I," *Power*, Vol 118, No. 2  
 [February 1974], pp S-12 - S-13. Reprinted with permission  
 of Power, February 1974.)

Table 8

Typical Railroad Car Dimensions and Capacities  
 (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*,  
 5th ed. [McGraw-Hill, 1973], p 7-45. Copyright by McGraw-Hill.)

Type of car	AAR * class	Nominal inside dimensions			Nominal outside dimensions			Volume ** cu ft x 100	
		Length	Width	Height	Length	Width	Height		
ACF center-flow hopper car	L0				39 ft	8 in.	10 ft 8 in.	14 ft 10 in.	29.7
ACF center-flow hopper car	L0				54 ft	8 in.	10 ft 9 in.	15 ft 1 in.	47.0
ACF center-flow hopper car	L0				59 ft	2 in.	10 ft 9 in.	15 ft 1 in.	52.5
GATX					42 ft	0 in.	10 ft 8 in.	14 ft 4 in.	26.0
Airslide hopper car	L0				54 ft	6 in.	10 ft 7 in.	14 ft 6 in.	41.8
Hopper car	HT	42 ft 10 in.	9 ft 8 in.		43 ft	10 in.	10 ft 6 in.	10 ft 8 in.	27.5
Gondola car	GB	41 ft 6 in.	9 ft 4 in.	2 ft 5 in.	42 ft	9 in.	10 ft 2 in.	6 ft 2 in.	9.6

\* Association of American Railroads.  
 \*\* 1 cu ft =  $2.832 \times 10^{-2} \text{ m}^3$ .

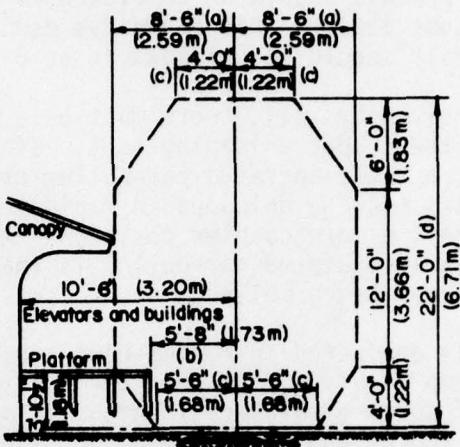


Figure 4. Typical railroad clearances for straight track. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-45. Reprinted with permission of McGraw-Hill and the Stephens-Adamson Mfg. Co.)

The condition of the coal, as received at the plant, may have been changed in transit by (1) freezing, (2) change in moisture content, or (3) size degradation. If freezing during transit is anticipated, the coal may be freezeproofed at the loading point either by spraying it with oil or spraying the car hoppers heavily with oil. The moisture content of the received coal depends on sizing, condition at loading time, and the weather conditions during transit. The coal may be delivered either saturated with moisture or so dry that the fines can be blown off as dust. To minimize dust loss, the coal can be dustproofed by spraying it with oil. Size degradation depends on the coal's friability and how much it is handled and shaken during transit. Size degradation is not important in the case of pulverized-coal firing, but if size is important for efficient firing, handling during transit should be minimized.

#### *Unloading*

The unloading operation depends mainly on the means of transportation used to deliver coal to the plant. Equipment such as car puller, shakers, dumpers, and conveyors are often used to facilitate the unloading operation. Under adverse conditions, such as when coal is delivered frozen, thawers, slice bars, or shakers may be needed. Various types of feeders can be used to set up a controlled flow to the next step in the handling process.

The unloading process should be completed as quickly as possible to minimize labor cost and to avoid expensive demurrage charges; generally, a 3-day supply should be unloaded in an 8-hour shift.

If coal is received by rail, there must be a means of bringing the hopper cars to the proper unloading spot. If only a few cars are unloaded at a time, a cable-operated car-puller or spotter is often used. When many cars must be unloaded in rapid sequence, such as with unit train deliveries, a more complex positioner may be needed. One disadvantage of a cable-operated car-puller is that it does not adequately control the car being pulled.

Coal is usually delivered in bottom-dump and top-dump cars. Unloading a bottom-dump car is simple when the coal is dry and flows freely; however, if surface moisture is high, it may be necessary to start the flow by rapping the car sides with a sledge or by dropping a heavy slice bar repeatedly on the coal. Another useful device is the car shaker (see Figure 5), which attaches to the top flanges of the car and vibrates it. The device is hung from a hoist and can be readily attached to or removed from a car. Coal from the car is discharged into a receiving hopper under the tracks. The hopper must have sides which slope more than 50 degrees\* and must have a capacity of more than one carload of coal. Top-dump cars can be emptied by grab buckets or clamshell buckets. In larger plants, rotary car dumpers (Figure 6) are used.

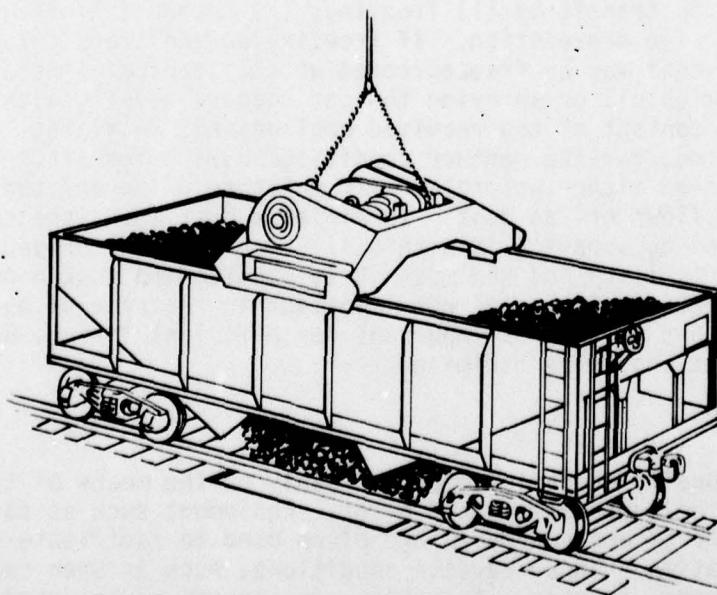


Figure 5. Car shaker. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-47. Copyright by McGraw-Hill.)

\*60 degrees if wet coal is handled.

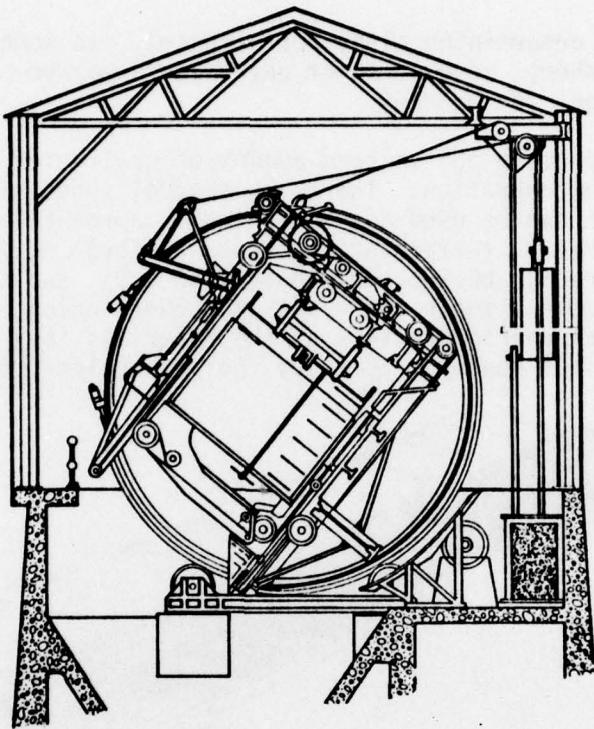


Figure 6. Rotary car dumper. (From A. J. Johnson and G. H. Auth, eds., *Fuels and Combustion Handbook*, 1st ed. [McGraw-Hill, 1951], p 632. Copyright by McGraw-Hill.)

In cold weather, when coal may be delivered frozen, a thawing pit is an effective means of facilitating unloading. A thawing pit is essentially a refractory-lined chamber between the tracks. Electric, gas-, or oil-fired heaters heat the refractory surfaces, which radiate heat to the bottom of the cars. At smaller plants, however, a thawing pit is not economically justified, and slice bars, sledges, or portable torches are often used.

Towers or bridges with grab buckets are commonly used to unload waterborne vessels that are not self-unloading. For self-unloading vessels, such facilities as an unloading boom conveyor are needed to receive the discharged coal.

After unloading, the delivered coal is moved to a storage area, where it is subsequently reclaimed and transferred to the firing equipment. Mechanical handling devices, such as feeders and conveyors, are available to facilitate the movement of this coal. In addition, weighing devices are used to determine the quantity of coal received and the amount of coal delivered to the firing equipment (this quantity

is needed for determining plant performance). In some cases, coal breakers, crushers, screeners, or pulverizers may be needed to properly prepare the coal for burning.

Feeders provide the uniform amount of coal which is necessary for proper conveyor operation. There are several types of feeders and conveyors that can be used to handle coal: apron feeders, bar flight feeders (Figure 7), reciprocating feeders, vibrating feeders, screw feeders (Figure 8), bucket elevators (Figure 9), and screw and belt conveyors. Table 9 shows the types of feeders which can be used based on the physical characteristics of the materials they carry, and Table 10 outlines conveyor types by their functions. For small plants,

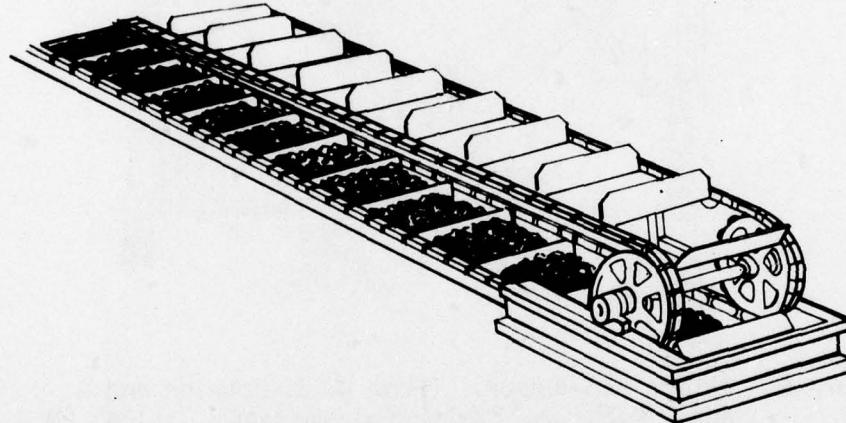


Figure 7. Flight feeder. (From "Power from Coal--Part I," *Power*, Vol 118, No. 2 [February 1974], p S-23. Reprinted with permission of *Power*, February 1974.)

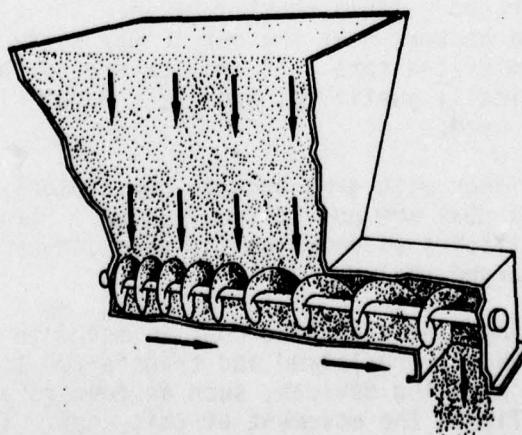
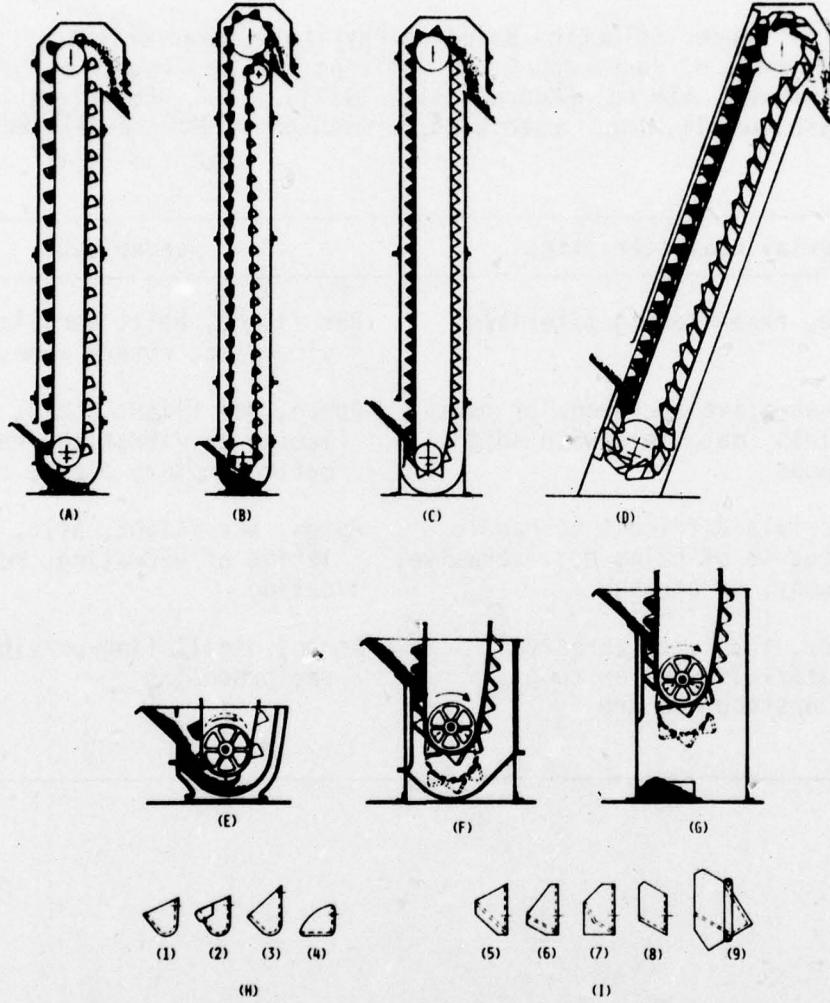


Figure 8. Screw feeder. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-27. Copyright by McGraw-Hill.)



**Figure 9.** Bucket-elevator types and bucket details. (a) Centrifugal discharge, spaced buckets. (b) Positive discharge, spaced buckets. (c) Continuous bucket. (d) Supercapacity continuous bucket. (e) Spaced buckets receive part of load direct and part by scooping from bottom. (f) Continuous: Buckets are filled as they pass through loading leg, with feed spout above tail wheel. (g) Continuous: Buckets in bottomless boot, with cleanout door. (h) Malleable-iron spaced buckets for centrifugal discharge. (i) Steel buckets for continuous-bucket elevators. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-12. Reprinted with permission of McGraw-Hill and the Stephens-Adamson Mfg. Co.)

Table 9

Feeder Selection Based on Physical Characteristics  
(From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-4. Copyright (c) 1963 by McGraw-Hill, Inc. Used with permission of McGraw-Hill Book Co.)

Material Characteristics	Feeder Type
Fine, free-flowing materials	Bar flight, belt, oscillating or vibrating, rotary vane, screw
Non-abrasive and granular materials, materials with some lumps	Apron, bar flight, belt, oscillating or vibrating, reciprocating, rotary plate, screw
Materials difficult to handle because of being hot, abrasive, lumpy, or stringy	Apron, bar flight, belt, oscillating or vibrating, reciprocating
Heavy, lumpy, or abrasive materials similar to pit-run stone and ore	Apron, oscillating or vibrating, reciprocating

Table 10

Conveyor Selection Based on Function Desired  
(From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 7-4. Copyright by McGraw-Hill.)

Function	Conveyor Type
Conveying materials horizontally	Apron, belt, continuous flow, drag flight, screw, vibrating, bucket, pivoted bucket, air
Conveying materials up or down an incline	Apron, belt, continuous flow, flight, screw, skip hoist, air
Elevating materials	Bucket elevator, continuous flow, skip hoist, air
Handling materials over a combination horizontal and vertical path	Continuous flow, gravity-discharge bucket, pivoted bucket, air
Distributing materials to or collecting materials from bins, bunkers, etc.	Belt, flight, screw, continuous flow, gravity-discharge bucket, pivoted bucket, air
Removing materials from rail cars, trucks, etc	Car dumper, car shaker, power shovel, air

portable versions of these devices may satisfy the operation requirements. Detailed descriptions and selection criteria are provided in the publications referenced below.<sup>6-10</sup>

#### *Outside Storage*

Depending on plant size and other factors, coal may be stored either in open-air piles or in enclosed storage bunkers. For a reserve or inactive stockpile, either a 30-day supply of coal (based on the maximum coal-burning month) or 20 percent of the unit's yearly coal need should be maintained, whichever is greater. Enclosed, in-plant bunkers should accommodate a quantity of coal sufficient to meet a 30-hour peak load demand; however, quantities exceeding the amount to be used should not be stockpiled. Exposure to the weather caused by open-air storage may reduce the value of the coal by reducing heating values, coking power, and size. In addition, coal may be lost through self-ignition or spontaneous combustion.

The first major step in successfully storing coal is the selection, acquisition, and preparation of a suitable site. The site should be on level, solid terrain and should be higher, if possible, than the surrounding area. It should be free of loose fill and waste material, properly drained, and should be void of any heat sources or pressurized gas lines that might rupture or explode. The selected area should be protected from prevailing winds, tides, flooded rivers, or ocean sprays. Solid retaining walls may be necessary if the stockpile is restricted to a relatively small area. Required storage space can be estimated by using the coal's bulk density.

Probably the most serious problem faced in coal storage is that of oxidation. The characteristics that determine the rapidity and degree of coal oxidation are rank, size, petrographic components, moisture content, iron disulphide content, and ash content. High-ranking coals oxidize more slowly than lower ranking coals. Since oxidation is primarily a surface phenomenon, highly friable coals exhibit more pronounced oxidation tendencies, since deterioration exposes additional surface area. Also, since smaller-sized coals have larger

<sup>6</sup>C. Carmichael, ed., *Kent's Mechanical Engineers Handbook, Design and Production Volume*, 12th ed. (John Wiley and Sons, Inc., 1969), pp 26-01--26-60.

<sup>7</sup>T. Baumeister and L. S. Marks, eds., *Standard Handbook for Mechanical Engineers*, 7th ed. (McGraw-Hill, 1973), pp 10-52--10-82.

<sup>8</sup>R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. (McGraw-Hill, 1973), pp 7-3--7-30.

<sup>9</sup>W. Staniar, ed., *Plant Engineering Handbook*, 2nd ed. (McGraw-Hill, 1959), Section 28.

<sup>10</sup>A. J. Johnson and G. H. Auth, eds., *Fuels and Combustion Handbook*, 1st ed. (McGraw-Hill, 1951), pp 601-634.

surface areas per unit weight, they will oxidize faster correspondingly. Heat produced by oxidation causes additional oxidation; for example, an increase of 15° to 20°F (-8° to -11°C) will double the rate of oxidation. Iron disulfide, or pyrites, within the coal will react during oxidation to form sulfuric acid, iron sulfate, and heat as well as promote size degradation which exposes more surface area. High-ash coals do not appear to oxidize as rapidly as those with lower ash contents. However, all coals may be stockpiled safely if the precautionary measures described below are observed.

Anthracite coal is relatively safe when stored in large, high piles in an area that permits drainage of excess water. Piles of anthracite should be capped with lump coal, or coated with asphalt to prevent wind erosion. Bituminous coal should be tightly compacted to a bulk density of 65 to 72 lb/cu ft (1041 to 1153 kg/m<sup>3</sup>) by using earth-moving equipment, in 1- to 2-ft (.3- to .6-m) layers. If the pile has not been sealed with oil, temperature- and pressure-caused changes in the internal air volume of the entrapped air will promote serious oxidation problems.

The top of storage piles should be crowned to permit drainage (see Figure 10). The top and sides should be capped with a 1-ft (.3-m) layer of fines topped with a 1-ft (.3-m) layer of lump coal.

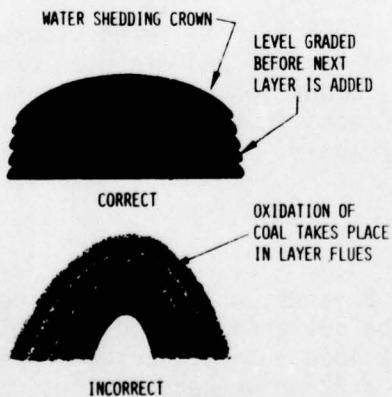


Figure 10. Cross section of correct and incorrect storage piles.  
(From A. J. Johnson and G. H. Auth, eds., *Fuels and Combustion Handbook*, 1st ed. [McGraw-Hill, 1951], p 636. Reprinted with permission of McGraw-Hill.)

Small piles of large-sized, double-screened coal, approximately 5 to 15 ft high (1.5 to 4.5 m), need not be compacted. Slack sizes, however, should have some compaction.

Large piles of subbituminous and lignite coals should be built with the same techniques used for bituminous coal, but layers should be thinner than 1 ft (.3 m) to insure good compaction. Since these coals deteriorate rapidly, it is not practical to cover stockpiles with coarse coals, but rather to use a compacted layer of fines. However, drifting of the fines may become a problem and windbreaks may have to be constructed perpendicularly to the prevailing winds.

Smaller piles of subbituminous or lignite coals should be thoroughly packed to retard oxidation. For short storage periods not exceeding 3 months, an oil coating may be more economical. As with bituminous coals, small piles of subbituminous or lignite are safely stored in conical piles, 5 to 15 ft (1.5 to 4.5 m) high. There is no real danger of heat buildup in such small uncompacted piles, because the heat generated by oxidation is easily dispersed. The other effects of oxidation may become a problem, however.

The amount of oil required to effectively prevent erosion and surface oxidation depends on coal size, porosity, and wetness. It is necessary to use more oil on high-moisture coals. If the coal has a relatively high porosity, a high-viscosity oil will be required to prevent significant amounts of oil from being absorbed into the coal. The amount of oil needed usually ranges from 1 to 8 qt/ton (1000 to 8.3 cm<sup>3</sup>/kg), with an oil coating thickness of 0.10 in. (2.5 mm) usually being adequate.

Regardless of the type of coal being stockpiled, using an oil coating to prevent wind erosion and minimize oxidation may lead to dangerous spontaneous combustion problems if the piles are not checked frequently. Cracks in the oil seal may cause a chimney effect and must be patched promptly. Chimneying will induce rapid oxidation near the air path.

#### *In-Plant Storage*

In-plant storage bunkers, which are difficult to modify after construction, should be designed to hold a quantity of coal sufficient to supply a 30-hr peak load demand. Large hoppers capable of feeding fuel to a furnace for a 72-hr weekend are desirable in areas where labor availability is a problem.

Although the shape of interior coal bunkers depends on space limitations and the desired flow rate, they must be designed to avoid "dead" pockets in which oxidation problems may develop. Discharge hopper sides should slope more than 60 degrees.

Bunkers, silos, or storage bins which depend on gravity to maintain steady flow should be located near the fuel-burning equipment to keep the coal flow as vertical as possible. Fires and explosions

can be prevented by keeping any heat sources such as hot-air ducts or steam pipes from the hopper vicinity. Adequate ventilation is required to prevent dangerous methane gas from building up when volatile coal is stored for a long period of time in an enclosed bin. Enclosed storage areas require a minimum of 2 cu ft/min of air per ton (1040 mm<sup>3</sup>/s of air per kg) of stored coal to prevent explosion hazards.

#### Direct Use of Coal

There are four major systems for burning coal in boiler operations: overfeed firing, underfeed firing, suspension (pulverized) firing, and fluidized-bed firing. Each requires its own particular equipment, operations, and coal.

##### *Overfeed Firing*

Overfeed-firing techniques require the addition of fresh coal on top of a bed of ignited coal or a grate. Several currently used burning systems use the overfeed method, including hand firing, moving-grate firing (traveling-grate and chain-grate stokers), and spreader stokers. Hand firing is usually restricted to furnaces having a grate area of less than 12 sq ft (1.11 m<sup>2</sup>) and therefore is not applicable to industrial-scale boiler plants.

Coal can be burned in suspension (suspended in an air stream or while falling) or on a grate (any open mechanical device for supporting a bed of burning coal). In a furnace equipped with an overfeed fuel supply system, raw coal is fed to a grate inside the furnace from above the burning coal layer. As the fresh or "green" coal begins to heat up, moisture and volatile matter (a complex mixture of combustible gases contained within the coal, such as hydrogen, methane, ethane, benzene, and various tarry vapors) are vaporized. (Consequently, the upper region of the fuel bed is referred to as the distillation zone. See Figure 11.)

After distillation, only the fixed carbon and ash remain. Ash is the incombustible matter remaining after complete burning. As the heating continues, the coke tends to settle to the lower zones of the fuel bed, under the pressure of the newly added "green" coal above it. This settling action usually leaves a protective ash layer above the grate, protecting it from the intense heat of the combustion zones above it.

In an overfeed system, air needed for combustion (primary air) flows through the grate and the ash layer and into the fuel bed. The primary air flowing through the bed oxidizes part of the carbon in the incandescent coke into carbon monoxide, which is subsequently oxidized into carbon dioxide. This region is called the oxidation zone. As the

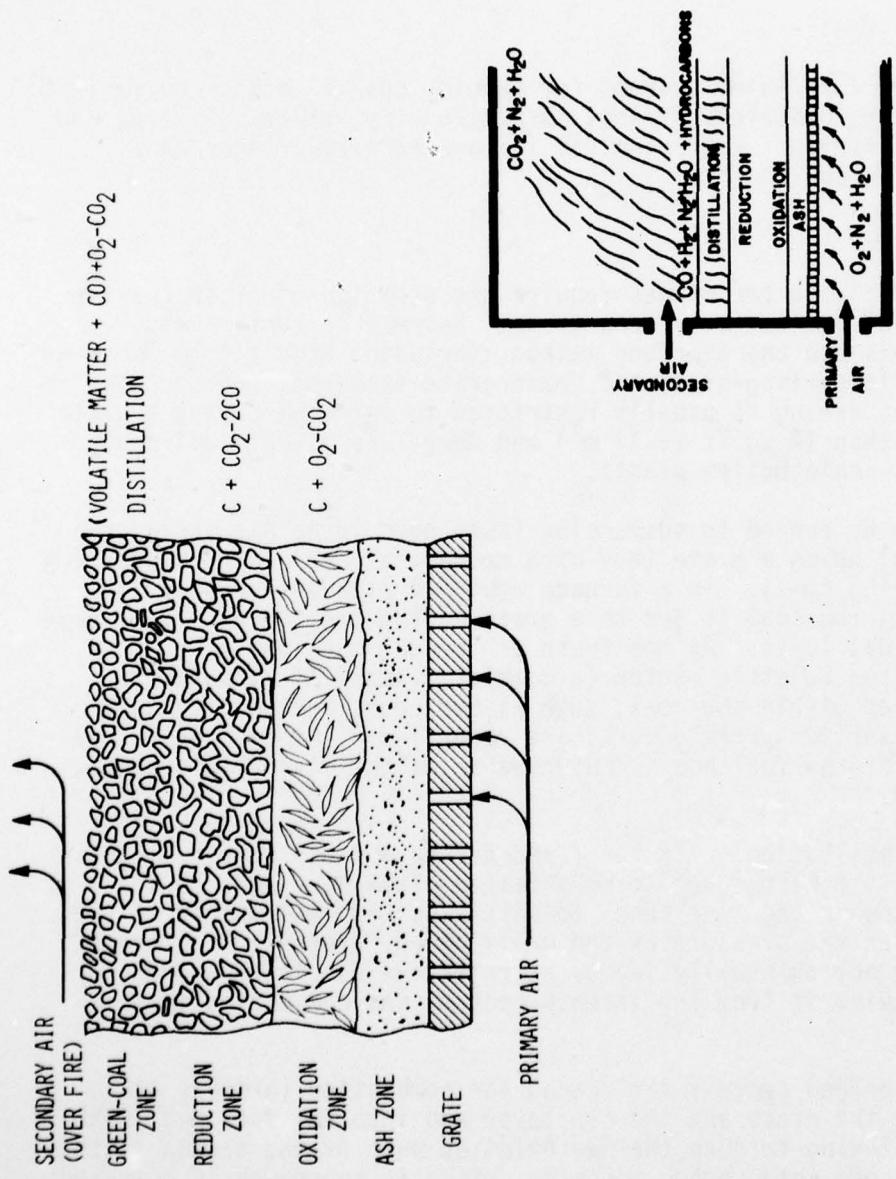


Figure 11. Combustion zones in an overfeed fuel bed. (From "Power from Coal-Part II," *Power*, Vol 118, No. 2 [February 1974], p S-23. Reprinted with permission of *Power*, February 1974.)

oxygen level is depleted in the bed, the incandescent coke reduces part of the carbon dioxide into carbon monoxide. The gases formed in this reduction zone pass through the distillation zone, mixing with the volatile matter and moisture above the fuel bed.

If there is enough oxygen for combustion of these gases above the fuel bed, additional heat energy will be released. This energy potentially represents 60 percent of the coal's heating value. It is essential to mix these gases thoroughly with oxygen to achieve peak efficiency and prevent the excess smoke caused by incomplete combustion of the tarry hydrocarbons and carbon particles in the volatile matter. Secondary air is added to the fire from above the fuel bed; it must be vented into the furnace at high velocities to create mixing and avoid stratification problems. Depending on the coal type, porosity of the fuel bed, and the amount of underfire air, various quantities of secondary air are needed.

In an overfeed system, burning rates are proportional to the primary air flow. The combustion rate is limited to the amount of oxygen diffusing through it. The underfire air rate is usually controlled by a forced-draft fan or by manipulating the stack dampers and thus the flow rate of the flue gas.

#### *Moving-Grate Firing*

The two most common types of moving-grate firing--the traveling grate (Figure 12) and the chain grate--feed from a hopper onto a moving grate below. The grate then moves through a combustion chamber like a conveyor belt.

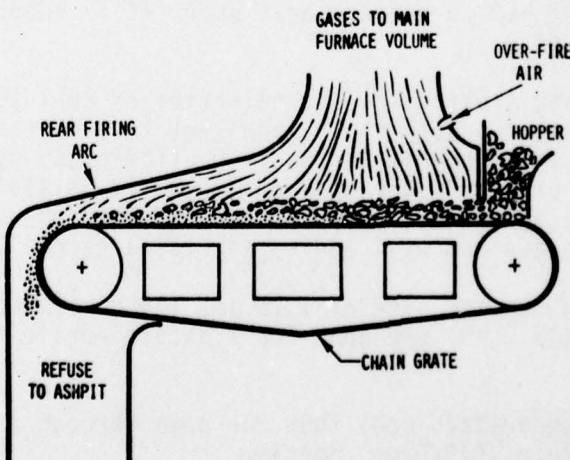


Figure 12. Traveling-grate stoker with rear firing arch.  
(From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 245. Copyright by McGraw-Hill.)

The main difference between the chain-grate and the traveling-grate stokers is the size of their grate openings. The iron bars making up the traveling grate are closer together, thus permitting the use of much smaller coal sizes, such as anthracite fines. The links of a chain grate, which are formed by iron grate bars, are usually staggered and interconnected by grate-wide rods. In the traveling grate, a drive chain at each side of the grate is connected to the grate at set intervals by crossbars. The fingers, or clips, form the grate surface overlap to prevent ash sifting. The maximum speed of a moving grate is dependent on the rate of coal ignition and can be adjusted by using a variable-speed gear box off a drive motor to accommodate load fluctuations. Firing rates of 15 to 30 lb/sq ft/hr (73 to 146 kg/m<sup>2</sup>/hr) are common for grates up to 25 ft (7.6 m) wide and 40 ft (12.2 m) long.

Radiation warms the coal as it moves through the combustion chamber and initiates the distillation process prior to ignition. Since more air is needed for combustion than distillation, it is necessary to control the amount of primary air being fed beneath any section of the grate by using a channeling system. Distillation begins immediately after the grate enters the combustion chamber and produces an atmosphere rich in volatile matter, but poor in oxygen. In the active-burning zone, air and combustible material must be nearly stoichiometric for high efficiency. Burning fixed carbon in the final zone of the grate required high levels of excess (secondary) air to prevent needless dumping of unburned fuel off the end of the grate. Channels and dampers are used to regulate air pressure across the fuel bed.

To promote rapid ignition of the incoming fuel and to insure complete mixing of the furnace gases, front and rear arches are incorporated above the fuel bed to reflect heat where it is needed and efficiently direct the gas flow.

In moving-grate stokers, proper selection of coal type and size guarantees satisfactory operation. Excellent results can be expected with anthracite, semianthracite, noncaking bituminous, subbituminous, lignite, and coke breeze.\* Caking\*\* coals should be avoided, because without sufficient agitation, lumps will form that inhibit air flow from beneath the grate and will add to excessive carbon loss.

Coal having a maximum size of 1.25 in. (31.8 mm) and fines smaller than 0.5 in. (12.7 mm) are good for a natural-draft furnace or for

\*Coke breeze is undersized coal that can pass through a 1/2-in. (12.7-mm) or 3/4-in. (19.0-mm) opening.

\*\*Caking coals are coals which, when heated at uniformly increasing temperatures in the absence or partial absence of air, fuse and become plastic.

one having a draft of 0.1 to 0.14 in. of water (25 to 35 Pa). Excessive use of fines in forced-draft furnaces will cause high carbon losses; best results are achieved with 3/4-in. (19.1-mm) nut coal or with small pieces having most of the fines removed. A high-ash coal is desirable with a traveling or chain-grate stoker because it deposits a protective ash layer above the grate after combustion. Clinker formation (high-temperature fusion of molten ash) is not a problem because agitation of the fuel bed is minimal and because the ash on the grate is cooled below fusion temperatures by the incoming primary air.

To minimize potential carbon losses and to regulate burning rates, the coal's moisture content should be raised by 12 to 14 percent before feed by spraying it with water.

#### *Spreader Stokers*

In a spreader stoker, most of the coal is oxidized while in suspension above the fuel bed. The spreader, usually a paddle-wheel device whose blades may angle alternately left and right, "throws" the coal toward the rear and sides of the furnace. The rotor blades are spaced to give the desired fuel-bed coverage and to partially pulverize the coal and enhance its combustion (see Figure 13).

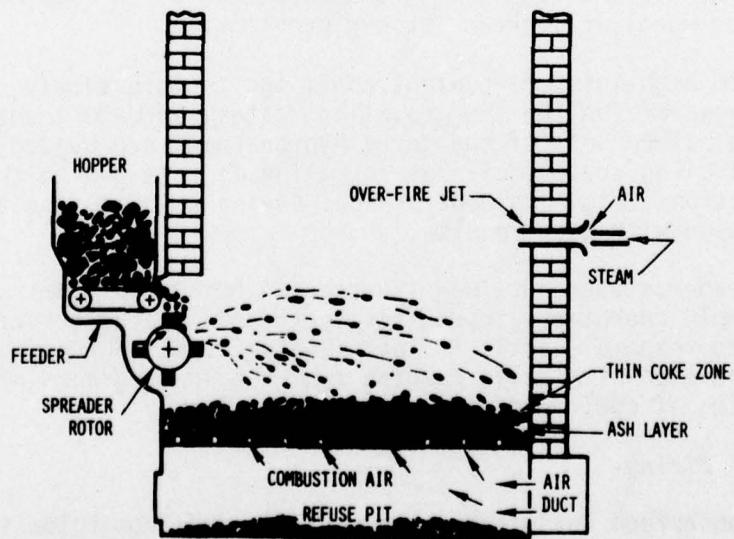


Figure 13. Spreader stoker. (From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 249. Copyright by McGraw-Hill.)

In mechanical spreaders that use heterogenous-sized coal, the larger lumps are thrown to the rear of the furnace, while smaller particles are thrown near the spreader. The problem of an uneven fuel bed can be offset in moving-grate furnaces by reversing the direction of the grate, which permits a longer combustion time for larger coal pieces.

The pneumatic process of spreader firing is nearly independent of coal size, distributes the coal more uniformly, and supplies secondary air to the furnace.

Adding secondary air above the fuel bed may be necessary if a mechanical stoker is used. In most cases, forcing most of the required air through the coal bed will provide peak efficiency; however, steam or air jets may be needed to insure adequate mixing of the overfire gases. Spreader stokers using a forced draft require that 5 percent of the grate surface area be open for primary flow. If natural draft ventilation is used, up to 20 percent of the grate must be vented.

Spreader stokers are best suited to coal-fired boilers that produce 5000 to 200,000 lb of steam per hour (0.6 to 2.5 kg/s). A spreader's capacity can be increased by adding extra feeding units, readjusting rotor blades, and enlarging the grate and furnace areas.

If an adequate ash-removal system is available, spreader stokers can operate efficiently with coals having ash contents of up to 35 percent; however, a coal having a high degree of surface moisture (20 percent or more) will create stoker problems.

Since high-moisture-content coals ignite more slowly, caking can result; however, unlike the traveling grates, spreaders are not affected by caking, since most of the tarry hydrocarbons are burned in suspension. As in traveling grates, clinker formation is rare due to the lack of fuel bed agitation. High-ash-content coal having a low fusion temperature can also be used with good results.

Spreader stokers are widely accepted because of their low initial cost, simple operation, insensitivity to coal characteristics, and ability to respond quickly to load fluctuations. Successful operation can be achieved with coals ranging from the lower grades of anthracite to lignite, if coal feed size is observed closely.

#### *Underfeed Firing*

In underfeed coal-firing, raw coal is fed from below the fuel bed, using a power ram or screw mechanism. Coal is pushed by pressure from coal directly following it along a trough to a retort, where it rises and spills onto the firing bed. As the green coal rises through the bed, the coal is heated, volatile matter is distilled, and ignition

occurs from above. Consequently, arches are unnecessary in furnaces using underfeed stokers. Ash is discharged by either a movable grate or by the motion of the incoming coal (see Figure 14).

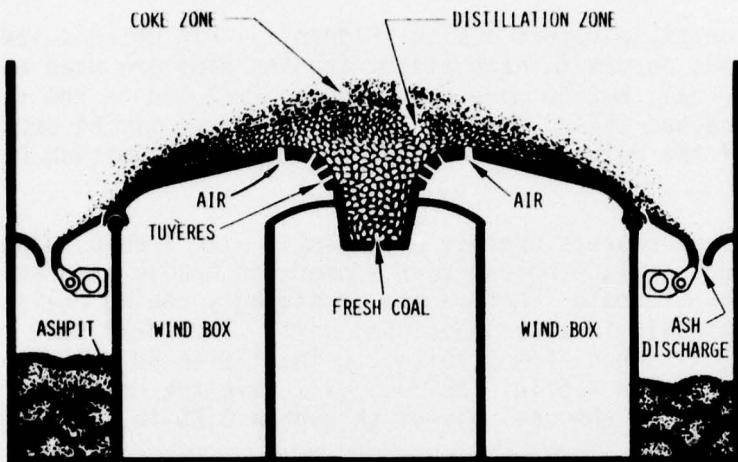


Figure 14. Cross-sectional view of a single-retort underfeed stoker. (From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 251. Copyright by McGraw-Hill.)

Primary air enters the bed through tuyeres (air louvres) located in the grate. Oxidation and reduction zones are located in the coal bed.

Underfeed fuel beds are usually thicker than those of overfeed systems; thus, greater quantities of air are required to insure combustion. For the average bed, a forced-draft fan provides primary air and should be maintained at about 1.0 in. of water pressure per 10 lb of coal per square foot per hour ( $0.16 \text{ Pa/kg-m}^2\text{-s}$ ). Thickness may vary greatly in larger beds, however, and higher efficiencies can be attained by using windbox dampers below the bed to control air flow in various zones. Primary air preheated to  $250^\circ$  to  $300^\circ\text{F}$  ( $120^\circ$  to  $150^\circ\text{C}$ ) generates higher burning rates.

Only a minimum amount of secondary air is required for this method of firing. Sufficient air should pass through the fuel bed to complete combustion of the volatiles; occasionally, however, unusually high burning rates require air or stream jets above the bed.

Generally, single retort (feeder) units operate efficiently for up to 25,000 lb/hr (3.1 kg/s) of steam, and occasionally as high as 40,000 lb/hr (5.0 kg/s). Higher load rates require multiple-retort designs.

In small, single retorts, worm or screw-feed systems are used. Screw-feed stokers, combined with a stationary grate, generate good results with coal feeding rates from 100 to 1200 lb/hr (12.6 to 151 g/s). If a higher burning rate is desired, a ram, piston, or plunger system should be used.

In a multiple-retort design (Figure 15), in which a series of units extends across furnace width, feeding rams are used not only to feed fresh coal, but to move the existing fuel bed to the rear of the stoker. The bed is inclined so that an overfeed firing section is on the edge of the retort, which insures complete combustion before ash discharge.

Underfeed stokers operate efficiently with free-burning to moderately caking coals; single-retort stoker can handle anthracite and most bituminous coals. Anthracite or strongly caking coals can be used successfully in a well-designed unit. The ideal size range for the feed coal ranges from 0.75 to 2.0 in. (19 to 50 mm). Nut and slack coal (smaller than 1.5 in. [38 mm]) will give the best results when no more than half of the coal passes through a 0.25-in. (6.4-mm) sieve.

The agitation of the fuel bed in underfeed-firing systems makes them suitable for burning caking coals. The amount of agitation is

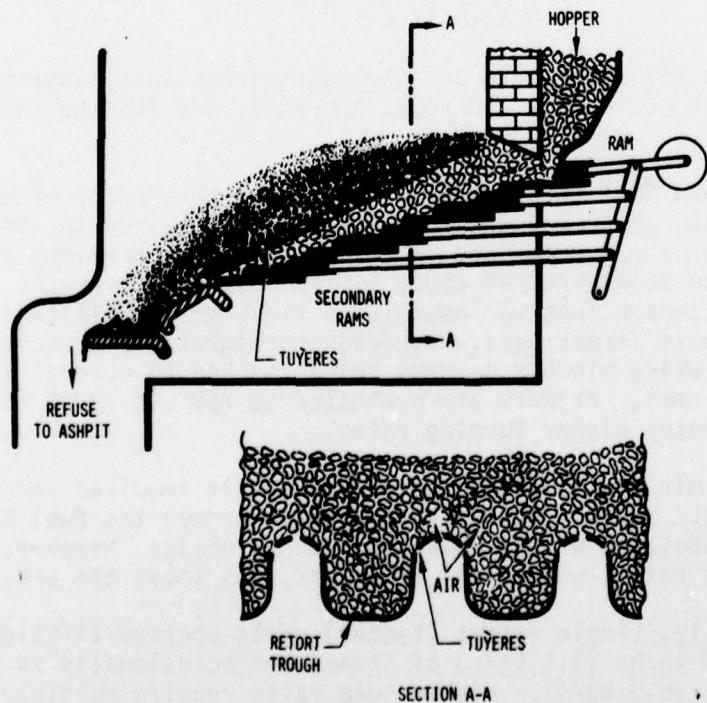


Figure 15. A multiple-retort underfeed stoker. (From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 253. Copyright by McGraw-Hill.)

directly related to the stoker design. The worm or screw feed, which generates mild agitation, would handle strongly caking coal. The ram feed, which has a movable grate, would use a low-caking coal. Best results are obtained with coals having a high ash-fusion temperature and slight-to-moderate caking tendencies. Ashes of free-burning coals tend to pile up and can cause unburned coal to spill over the burning fuel bed into the ash-handling system.

In large units having high firing rates, it may be necessary to use clinker grinders at the end of the grate to break up large lumps before dumping the ash. This is especially necessary when high-ash coals are used.

The use of coal grinders prior to feed will improve air control within the furnace. Because of its increased surface area, ground coal will burn more completely with reduced carbon loss.

#### *General Overfeed and Underfeed Firing Considerations*

The most important considerations in choosing coal for a particular stoker type are ash content, caking tendency, raw-fuel size, and clinker formation. Table 11 relates fuel requirements to specific stokers.

Ash Content. When coal of different ash composition or ash content is considered for burning, the design of such components as the superheater, reheat, economizer, and air heaters may have to be checked. Coal having a high ash content will not adversely affect a spreader stoker's performance, but it may hamper other boiler components. Excessive ash levels can cause slagging and bridging of boiler tubes. In addition, the size of the draft system and the type and number of dust collection devices may need to be changed.

Caking Tendency. A nonagglomerating coal should be used in underfeed systems. If coal drifts onto the bed, high carbon loss and poor efficiency can result. If a low-volatile coal is burned, more grate area may be required for complete combustion.

Raw Fuel Size. Segregating coal particle sizes in the feed supply may seriously affect a stoker's operation. A spreader stoker can burn a wide variety of coal, although it was originally developed to use the lower grades.

Since the spreader stoker system uses a thin-running fuel bed, anthracite should be mixed with lower grades of coal before feeding to insure complete combustion. Mixtures containing between 25 and 50 percent anthracite are most desirable. Since only part of the combustion occurs on the bed, fuel size must be regulated. The ideal fuel

Table 11

\* Nominal Characteristics and Uses of Industrial Stokers  
 (From C. Carmichael, ed., *Kent's Mechanical Engineers Handbook, Design and Production Volume*, 12th ed. [John Wiley and Sons, Inc., 1969], p 2-35. Reprinted by permission of John Wiley and Sons, Inc.).

	Type		
	Overfeed	Underfeed	
Application	Inclined grate Spreader type	Traveling grate Chain-grate	Single retort Multiple retort
Fuel	Anthracite, high-volatile coking coals, lignite, coke and refuse fuels	All except strongly coking bituminous coals Best operation with 10-20% ash coals	High-volatile coking coals, slack, or fines High ash fusion desirable
Fuel-bed thickness, in. (mm)	6-7 (52-178) (bituminous)	5-6 (127-152) (No. 3 buckwheat) 4-5 (102-127) (No. 4 buckwheat)	
Continuous combustion rate, max for best efficiency, lb per hr per ft <sup>2</sup> (g/s-m <sup>2</sup> ) of grate area	30 (40.7) (IG)*	50 (67.8) (bituminous) 45 (61.0) (No. 3 buckwheat) 35 (47.5) (No. 4 buckwheat) 35 (47.5) (Coke breeze)	30 (40.7) (SR, 6-7' wide)* 40 (54.2) (SR, 7-10' wide)* 40 (54.2) (MR)*
Draft, inches of water (Pa), natural	0.2-0.6 (49.8 - 149.3)	0.2-0.6 (49.8 - 149.3)	
forced	1-3 (248.8-746.5)	1-3 (248.8-746.5)	2-4 (497.7-995.4)

\* IG = inclined grate. SR = single retort. MR = multiple retort.  
 Note. All stokers perform better with preheated and overfire air. Where forced draft is used, a windbox should be zoned to secure optimum amount of air for various sections. Preheat temperature of about 350 F (176.7 C) is best for minimum stoker maintenance.

has a top size of 0.75 in. (19 mm). Larger sizes may be used, depending on the coal's volatile matter content. Using an extremely fine coal, however, may cause excessive carbon losses, since the unburned fines will leave the chamber with the flue gases.

The most versatile stokers are the chain-grate and traveling-grate systems, which can burn any type of coal except a strongly caking bituminous. Small-sized anthracite, such as no. 2, no. 3, and no. 4 Buckwheat, river-coal, and silt\* can be burned efficiently, and bituminous is an excellent stoker fuel. If the stoker is operating with a natural draft, the top size of fuel should be limited to 1.5 in. (38 mm) to allow sufficient air travel through the bed; with a forced draft, best results are obtained with a top size of approximately 0.75 in. (19 mm). If a subbituminous or lignite coal is used, a larger top size may be used, since these types have higher volatile-matter contents. High moisture content, however, may limit top size to 1 in. (25 mm) to insure complete combustion.

Clinker Formation. One of the major drawbacks in operating a stoker, especially one with a moving grate, is the problem of clinker formation. A change in raw fuel size, an attempt to reduce ash-fusion temperatures, improper mixing of various grades of coal, or even simple neglect of specific furnace operating procedures can cause the problem.

Two conditions must be present for clinker formation. First, a sufficient number of incombustibles must be grouped together, and second, the temperature must be high enough to melt the ash, which will cement other infusible masses on the fuel bed. If there is a reducing atmosphere, the ash-fusion temperature of the coal will decrease. If various coal grades are mixed before combustion, the resultant mixed ash will generally have a lower fusion temperature than any of its components will have separately.

Decreasing the coal size causes more contact between two pieces of coal. If the ash is assumed to be evenly distributed throughout the coal, each ash particle is more likely to make contact with another ash particle and fuse into clinkers. Coal fines ranging from 1/8 to 1/16 in. (3.2 to 1.6 mm) may form three to four times as much clinker material as the same type of coal ranging from 1/2 to 1 in. (12.7 to 25.4 mm) in size. Consequently, a small, low-ash coal may produce more clinkers than a larger, high-ash coal. Low-ash coals tend to form a hard, glassy clinker that is difficult to remove from the grate or furnace walls; high-ash coals tend to form a loose, porous clinker.

\*The sizes of these coals are: no. 2 buckwheat (rice)--5/16 x 3/16 in. (7.9 x 4.8 mm), no. 3 buckwheat (barley)--3/16 x 3/32 in. (4.8 x 2.4 mm), no. 4 buckwheat--3/32 x 3/64 in. (2.4 x 1.2 mm). River coal and silt are still smaller sizes which are often dredged from rivers into which they were dumped originally as unusable.

Direct melting of the ash or some of its constituents produces a hard clinker. If the ash fuses, a large cake will be formed, but if the constituents melt, the clinker will be distributed throughout the ash and form small, hard pieces. Hard clinker is usually the result of bad firing methods. Soft clinker is caused by slagging of the ash; its consistency varies from a thick paste to a heavy oil.

Operating conditions of the fuel bed also influence clinker formation. Permitting the fuel bed to thicken, for example, increases the resistance of the bed to the passage of air, which produces a large reducing zone within the fuel bed. If the design fuel for a specific stoker is used, the bed thickness should be approximately 4.5 to 5.0 in. (114 to 127 mm). The bed thickness will increase if a lower grade of coal is burned and the operation's desired steam output remains constant. Adding excess underfire air can cool the ash layer. A high-ash coal should be burned with a thin fuel bed since the cooling influence of the primary air passing through the bed will help decrease the high temperatures that cause clinker formation.

#### *Pulverized Firing*

Coal pulverization is the most widely used method of burning large quantities of coal. When coal is ground to the fineness of silt or flour, for example, it will take on the characteristics of oil; however, its use is much more complex than oil. Preparation requires drying and pulverizing the coal, transporting it to the furnace, and injecting it into the furnace volume at the desired rate. Combustion will be more efficient since the system is designed to use a minimum of excess air.

The basic components of a pulverized-coal firing system are: the pulverizer, which crushes the coal to the required degree of fineness; the pneumatic system, which transports the coal to the furnace; and the burner, which mixes the air and fuel, ignites it, and distributes it into the furnace. Peripheral equipment includes an air preheater for drying the coal before pulverization, a coal-feed system to meter the coal into each pulverizer, and the fuel-air-mixture pneumatic transport ducts.

Combustion. In the pulverization system, hot air streams pneumatically inject the coal particles into the furnace. Approximately 15 to 20 percent of this is primary air; the remaining 80 to 85 percent is introduced around the burners as secondary air. The finely divided fuel is subjected to extreme heat that instantly distills the volatile matter. The carbon remaining after the distillation heats to incandescence and the secondary air introduced around the burner completes the combustion process.

Coal Characteristics Which Influence Performance of Pulverizers. If large quantities of raw coal are handled, a crushing device may be

necessary to roughly grind the coal to reduce the pulverizer's load. Depending on the pulverizer's size and how it is operated, coal size must be limited to achieve operational efficiency. When a pulverizing mill is small or operated at speeds below 75 rpm, the coal size should be no larger than 0.75 in. (19 mm). Larger units, or those operating at higher speeds, are very efficient when coal size is restricted to 1.0 to 1.25 in. (25.4 to 31.8 mm). Removing ferrous materials which can be harmful to the pulverizer material will usually minimize pulverizer downtime; a variety of magnetic separators is available for this purpose. The quality of coal as it leaves the pulverizer depends on its grindability and on the content of its moisture, ash, and volatile matter. Figure 16 shows the influences of grindability, moisture content, and fineness of grind on pulverizer capacity. The grindability of coal is measured by the Hardgrove machine (see ASTM D409). The test described in ASTM D409 measures the relative amount of energy required to pulverize a specific amount of coal in comparison to that of a standard coal so that pulverizer capacities and the power required to crush a given coal can be compared.

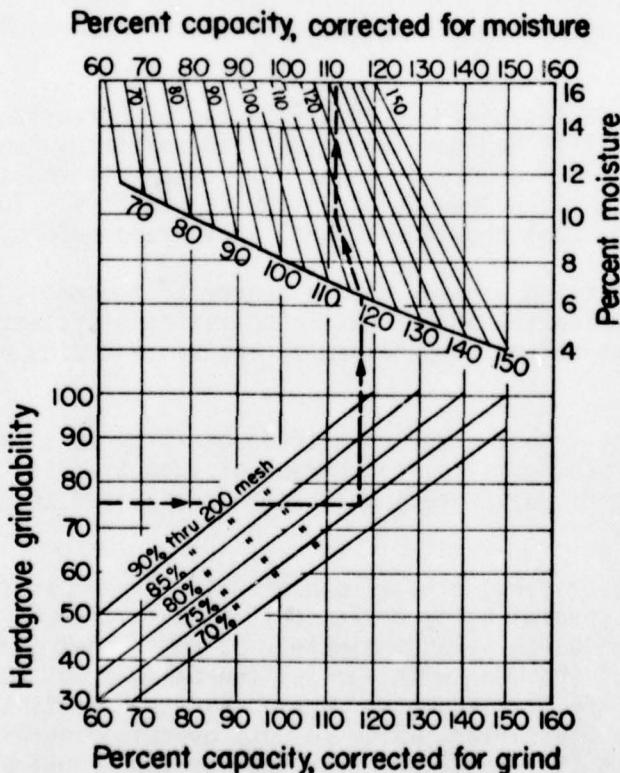


Figure 16. The influence of grindability, moisture content, and fineness of grind on pulverizer capacity. (From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 257. Reprinted with permission of McGraw-Hill and Combustion Engineering Air Preheater.)

A coal's surface moisture, rather than its inherent moisture, is much more likely to affect the pulverizing system by clogging. To prevent this, superheated air (at temperatures of 250° to 600°F [120° to 316°C]) is introduced into the pulverizer unit to facilitate the drying process. The units must be able to handle large quantities of hot air, permit sufficient air circulation within the pulverizers to keep relative humidities below 100 percent, and facilitate dissipation of excess heat evolved during pulverization. Since methane gas is released during pulverization, premature ignition of the air-fuel mixture leaving the pulverizer may occur if its temperature is too high. Generally accepted safe temperature levels are 120 to 140°F (49 to 60°C) for lignite coals up to 200°F (93°C) for anthracites.

The capacity of a pulverized-coal firing system is governed partially by a coal's ash content; more high-ash than low-ash coal will be required to provide a given Btu output.

A coal's volatile content determines the fineness of pulverizer output. Because high-volatile coal ignites faster, it requires a coarser grind; however, low-volatile coals are usually somewhat softer and have a higher grindability, which offsets the need for finer pulverization.

A coal's caking tendency is also a factor affecting pulverization. As a caking coal is heated, its pulverized particles swell and form lightweight, porous chunks of coke. The escape of these coke particles with the flue gas can lead to excessive carbon loss. To avoid this problem, caking coal should be highly pulverized before combustion.

When specifying a given coal's degree of fineness, the user must consider the economics of the entire pulverizing system; e.g., a unit's efficiency must not be compromised by excessive drying or pulverizing costs.

Pulverizer Types. There are three basic types of pulverizers: ball mills, crushing mills, and hammer or impact mills. Table 12 shows the type of pulverizers which may be employed to pulverize various types of coal.

The ball, or tube, mill is a horizontal drum, partially filled with steel or special alloy balls of 1- to 2-in. (25.4- to 50.8-mm) diameter, which revolves at approximately 20 rpm. Coal size is reduced by impaction of the coal with the falling balls or by attrition and crushing from the sliding mass. Heated air transports the pulverized fuel through a classifier, which rejects oversized particles. These large particles (tailings) are recycled for additional pulverization. The ball mill has a low maintenance cost, is reliable, and responds well to changes in fuel demand; however, it consumes much more power per ton of processed coal than other types of mills.

Table 12

Types of Pulverizers for Various Coals and Coke  
 (From G. R. Frying, ed., *Combustion Engineering* [Combustion Engineering, Inc., 1966], p 16-12. Reprinted by permission of Combustion Engineering, Inc.)

Type	Ball or Tube Mill	Crushing Mills	Impact and Attrition Mill
Low volatile anthracite	x	-	-
High volatile anthracite	x	x	-
Coke breeze	x	-	-
Petroleum coke (fluid)	x	x	-
Petroleum coke (delayed)	x	x	x
Bituminous coal (low volatile)	x	x	x
Bituminous coal (medium volatile)	x	x	x
Bituminous coal H.V. "A"	x	x	x
Bituminous coal H.V. "B"	x	x	x
Bituminous coal H.V. "C"	x	x	-
Subbituminous coal "A"	x	x	-
Subbituminous coal "B"	x	x	-
Subbituminous coal "C"	-	x	-
Lignite	-	x	-
Lignite and coal char	x	x	-
Brown coal	-	-	x

The primary pulverizing mechanism of the crushing mill is compression. In the roll-race or ball-and-race systems, coal is ground between two surfaces moving relative to each other. Air is the primary means of circulating the coal through the grinding zone and of transporting the fuel-air mixture to the burner. The ball-and-race pulverizer works on a ball-bearing principle. Large balls, several inches in diameter, are located between two races, above and below the crushing balls. Large springs that apply tension to the raceways control the degree of fineness. The roll-race pulverizer system has three large rollers (1 to 2 ft [.3 to .6 m] in diameter) between two raceways. The rollers, mounted to a central pivot or axle, are the primary crushing system; pressure applied directly to the axle regulates the degree of pulverization. Both the ball-and-race and the roll-race systems consume little power, are compact, quiet, high-capacity systems, and have low maintenance costs.

The hammer or impact mill, which is used in smaller operations, is well-suited to moist coal. In the hammer mill, rotating hammers strike and shatter large coal particles in midair. The second stage occurs when the partially ground coal passes to the outer edges of the rotating hammers and is crushed between a stationary wall and rotating hammers. Abrasion with other coal particles also occurs. An exhaust fan removes the ground particles and a classifier recycles large particles through the system. Impact pulverizers generally cost little initially, but have significantly higher long-range maintenance and power costs than ball mills or crushing mills.

Pneumatic Systems. In most modern pulverized-coal firing systems, the coal is removed from the bunker and pulverized; the fuel-air mixture is then routed directly to the burners by a pressure or suction pneumatic system, whose fans may be upstream or downstream from the pulverizers.

In the pressure system, the primary air fan is located on the intake side of the pulverizer. Air ducted through the pulverizer picks up coal particles and transports them to the burner. Since the primary air fan handles clean air and is therefore not subjected to the abrasive action of pulverized coal, an efficient rotor design with high tip speeds may be used.

In suction systems, the fan is located on the exhaust side of the pulverizer. To comply with explosion prevention standards, the exhaust housing must be able to withstand 200 psi (1.38 MPa) pressure. The fuel-air mixture is drawn through the pulverizer under negative pressure and directed toward the burner, thus subjecting the fan to considerable abrasion and limiting its design to the inefficient paddle-wheel types.

Burners. Burners provide stable ignition by introducing a uniform fuel-air mixture into the furnace and by controlling flame shape. The

vanes may be adjusted to produce a long, diffuse flame or a short, turbulent fireball. The latter shape usually yields a high temperature and improves combustion efficiency. The burners completely mix the gases inside the furnace by means of ribs that "spray" the fuel-air mixture into the furnace area. Secondary air is introduced at the burner's edge.

Firing methods (vertical, horizontal, and tangential) are characterized by the location of the burners in the furnace (see Figure 17).

In horizontal firing, the burner is usually wall-mounted and the flame is directed across the furnace box. High turbulence levels and burning rates can be obtained by placing burners in the furnace so that they oppose each other. Depending on the rank of coal used, the degree of turbulence within the furnace must be regulated to avoid excessive slag deposits caused by high temperatures and retention of this slag in the furnace for extended periods of time. Since horizontal burners can burn up to 900 lb (410 kg) of coal per hour per burner, only a few are required.

Older designs use the vertical firing method, which is especially suited for high, narrow furnaces. The burner, placed on top of the furnace, ejects the flame downward. The long flame travel makes this method suitable for high-volatile coals and for low-volatile coals requiring long retention times for complete combustion. Secondary air is frequently injected horizontally into the furnace for increased turbulence.

In a tangentially fired system, burners are located at the four corners of the furnace and the flames are directed tangentially toward the circumference of an imaginary circle in the center of the furnace. A cyclone motion is created which tends to spread flames throughout the entire furnace area. Rapid and complete combustion is assured, since any unburned combustible material leaving the tail of one flame will be caught by a succeeding one. The fuel-air ratio is not critical when this method is used. With little excess air, tangential firing is capable of high firing rates (furnace heat release rates) and gives excellent combustion efficiency.

The burners can be tilted vertically in the tangential firing method. For example, if the burners are pointed upward, the gases will approach the superheater sooner, there will be less time for heat to radiate to the boiler walls, and higher superheat temperatures will result. If the burners are pointed downward, gas retention time increases, thus decreasing the gas temperature in the convective section of the boiler.

General Considerations of Pulverized-Coal Firing. Pulverized-coal firing has many advantages. The burners can readily burn either gas or oil, and the low level of unburned combustibles in the furnace at a

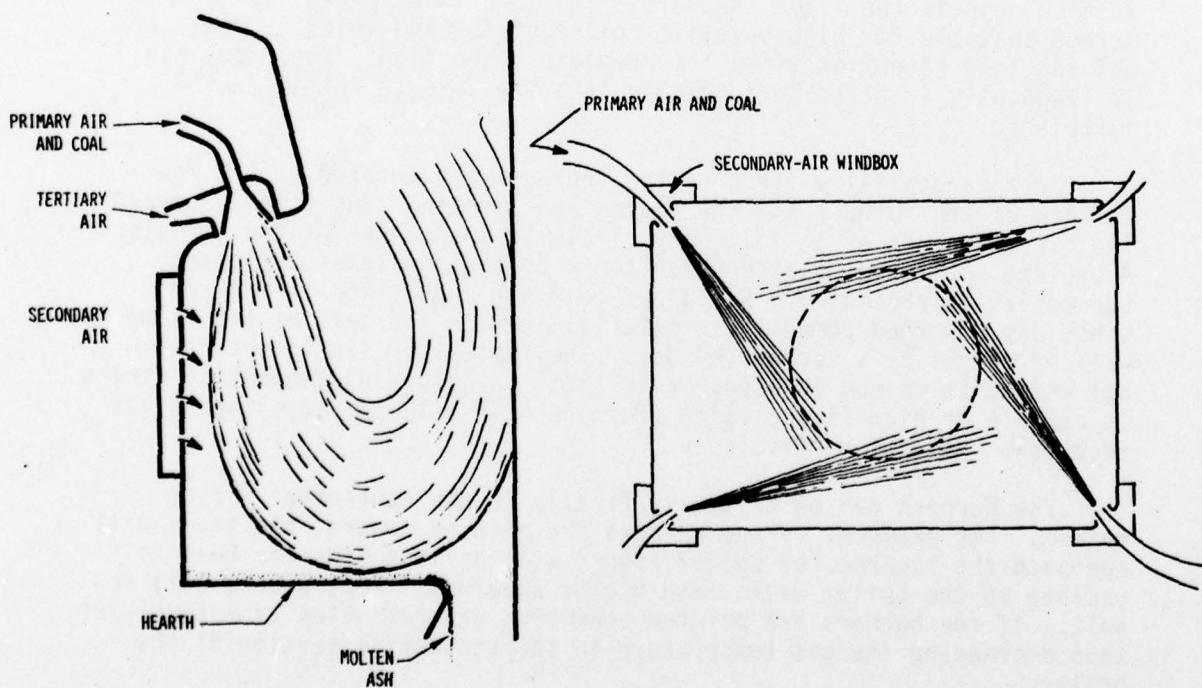
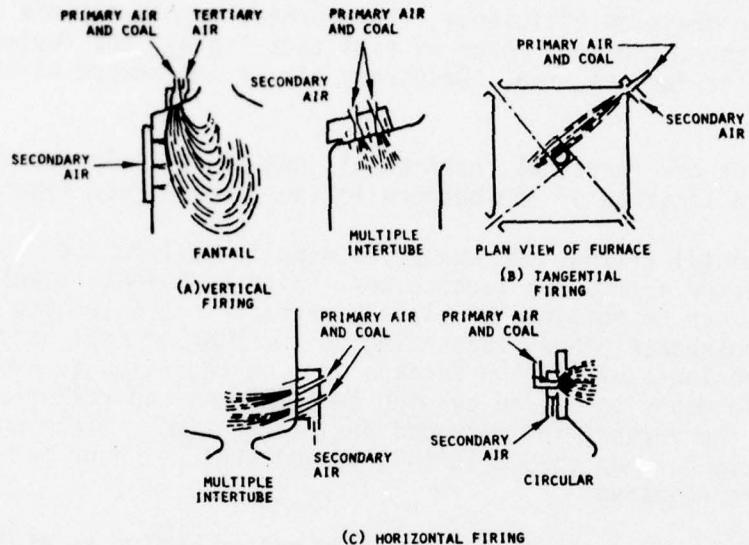


Figure 17. Burner and furnace configurations for pulverized-coal firing. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 9-21. Copyright by McGraw-Hill.)

given time increases a boiler's capability of quickly meeting wide load fluctuations. The burners are generally designed to give peak performance at the unit's rated capacity. When the load falls, however, an ignition problem may arise, but an ignited oil burner (pilot) will correct the problem.

The following phenomena may be anticipated in pulverized-coal firing operations:

1. Fuel ignition occurs almost spontaneously, since the ignition rates vary inversely with coal-particle diameter. This relationship is the result of an increase in the surface-area-to-volume ratio for smaller particles, which have more surface area exposed to available oxygen in the combustion chamber.
2. High-volatile coals require lower ignition temperatures than low-volatile coals.
3. Swelling of coal particles occurring during distillation increases particle volume two to eight times. Although swelling increases the overall firing rate, it may lead to excessive carbon loss, since the swollen coal particles become less dense and are apt to be carried from the chamber by escaping flue gas. Regulating the degree of pulverization will solve this problem.
4. Burning rates vary in proportion to furnace temperatures.
5. Carbon monoxide levels are low when combustion is incomplete; however, solid carbon losses may be excessive.
6. A long residence time in the combustion chamber, together with high levels of turbulent mixing, should provide complete combustion of the pulverized coal. High efficiency will be obtained if at least 65 to 85 percent of the pulverized coal will pass through a 200-mesh screen, while not more than 2 percent is retained on a 50-mesh screen.

Air velocities and the burner's controlling vanes should be adjusted to keep ignition at least 3 to 12 in. (76 to 305 mm) from the nozzle tip. Ignition too close to the burner wall will cause high localized temperatures and undue wear. The velocity of the fuel-air mixture should be regulated to be slightly greater than the ignition rate. A lower velocity will invite flashback and burning in the transport system, while a higher velocity will over-disperse the mixture and create unsteady combustion conditions.

The fuel-air ratio must also be controlled for efficient system operation. The amount of air draft required, whether for drying, classifying, or merely transporting the fuel, will vary daily. A successful operation will require some form of compromise. A generally

applied rule is that the percentage of primary air should be equal to the coal's volatile content. For low-volatile coals, however, this formula is inadequate for a proper pulverizer operation. After pulverizing and transporting the coal to the burner, some form of bleeding system may be incorporated to remove excess air.

The greatest disadvantage of pulverized firing is related directly to the coal's ash content. After pulverization, up to 85 percent of the ash contained in the coal will be carried through the boiler with the combustion products. In the combustion chamber, the high gas temperatures soften the ash, and slagging problems develop. As much as half of the ash entering a furnace remains as deposits on furnace walls and boiler surfaces. The heat-transfer capability of the boiler (its efficiency) is reduced as ash deposits accumulate. Excessive deposits also block the flow of gases around the convection surfaces, which increases draft losses through the system and reduces the combustion rate. Since slagging leads to erosion and weakening of boiler surfaces, ash-removal systems will be required. Pulverized-coal systems generally require the use of air pollution control equipment.

#### *Fluidized-Bed Combustion*

Recently, interest in fluidized-bed combustion has increased, although equipment is not readily available commercially.

If a gas stream flows upward at a steadily increasing rate through a bed of particles, the pressure drop across the bed will eventually become equal to the weight per unit of cross-section area plus the friction of the bed against the wall. This critical velocity is called the "minimum fluidization velocity." As the gas velocity increases, the bed expands to allow the additional gas flow to pass through it in the form of bubbles. When the gas velocity is three to five times the minimum fluidization velocity, the system resembles a violently boiling liquid. As a result, thermal equilibrium between the gas and particles in the bed is quickly established.

Heat is transferred to a heat exchange surface in a fluidized bed when the particles briefly touch the surface, give up heat, and return into the body of the bed. High heat transfer rates generally occur when the gas bubbles promote rapid mixing of solid particles.

Figure 18 is a schematic of a fluidized-bed combustor investigated by the British Coal Utilization Research Association. Essentially, fine coal particles are fed into a bed of coal and ash particles. Air is passed through the bed at a rate sufficient to fluidize it and to effect coal combustion. Heat exchange tubes are located within the fluidized bed to take advantage of the favorable heat transfer conditions in the bed.

Some potential advantages of a fluidized-bed combustion system over conventional combustion systems are:

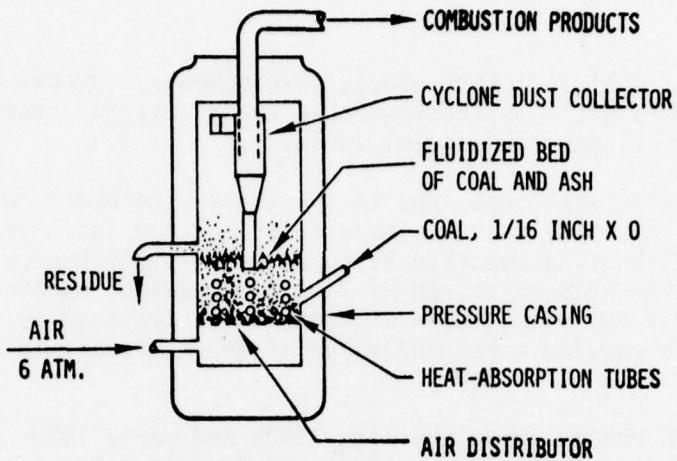


Figure 18. Pressurized fluidized-bed combustor. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 9-23. Copyright by McGraw-Hill.)

1. Low fuel-bed temperatures cause less formation of nitrogen oxides and retention of some sulfur of certain coals in the residues.
2. The lower fuel-bed temperature results in less volatilization of the sodium and potassium in the coal, with the consequent reduction of deposits on and corrosion of heat transfer surfaces.
3. The reduced deposits and corrosion will probably raise maximum steam temperatures above present levels and hence improve overall plant efficiency.
4. Since there is a better heat transfer rate when heat transfer tubes are immersed directly in the bed, fewer heat transfer surfaces are required. It is estimated that in comparison with a conventional pulverized coal-fired steam generator having the same capacity, successful operation of a fluidized-bed combustor to central stations would reduce capital costs by 10 percent.
5. The costs of coal crushing will probably decrease, since fine grinding to pulverized fuel sizes is unnecessary.
6. The fluidized bed could use coal of high and/or variable ash content.

#### Coal Gasification

Recent serious shortages of both gas and oil have spurred the development of alternate clean fossil-fuel sources for residential and light-industrial applications. Both the large reserves and the widespread availability of coal throughout the United States indicate the

importance of coal in future energy developments. Recent efforts have centered around coal gasification as a substitute for costly and diminishing domestic and industrial fuels.

Coal gasification was used in the early nineteenth century, when the widely used "city gas" was made from coal and coke-oven gas. City gas, having a heating capacity of approximately 500 Btu/cu ft (18.6 MJ/m<sup>3</sup>), was the primary source of fuel for cooking, heating, and street lighting until the 1930s, when it began to be replaced by electricity or natural gas having a heating value of approximately 1000 Btu/cu ft (37.3 MJ/m<sup>3</sup>).

Research began during the late 1940s and early 1950s to produce a high-Btu gas from coal, since the demand for natural gas was increasing faster than the discovery of reserves. In the past several years, coal gasification technology has drawn increasing attention, due to the major imbalance between the supply and demand of natural gas. Recently, a large number of firms announced plans to construct commercial coal gasification plants within the United States.

The various coal gasification techniques are classified by the heating value of the gas they produce. Low-Btu processes produce a gas of less than 200 Btu/cu ft (7.5 MJ/m<sup>3</sup>); medium-Btu gases have a heating value of 200 to 500 Btu/cu ft (7.5 to 18.6 MJ/cm<sup>3</sup>); and high-Btu gases are approximately 1000 Btu/cu ft (37.3 MJ/m<sup>3</sup>).

#### *High-Btu Gasification*

Most of the recent coal gasification research has been concerned with producing high-Btu gas of pipeline quality. Present municipal distribution networks were designed for natural gas of approximately 1000 Btu/cu ft (37.3 MJ/m<sup>3</sup>). Conversion to a gas of lower heating value would require that these networks handle a correspondingly higher volume to deliver the same effective heating value. Furthermore, gases of lower heating value often contain large amounts of hydrogen, which can cause hydrogen embrittlement of pipelines.

Most high-Btu gasification processes react oxygen, steam, and coal to produce a gas comprised of carbon monoxide, hydrogen, and carbon dioxide, as shown in the following reaction:

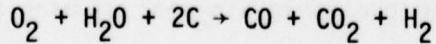


Table 13 outlines these processes and some of their major characteristics.

Depending on the type of gas-solid contact in the gasification reactor, coal gasification processes may be classified as moving-bed, entrained-bed, or fluid-bed processes.

Table 13  
Coal Gasification Processes (High-Btu Gas)

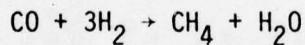
Reactor Bed Type	Process	Status	Capacity, Tons/ Day (Mg/Day)	Gasifying Medium	Residue	Remarks
Moving Bed	Lurgi* (German)	Commercial	1,000 (907)	Steam Oxygen	Dry Ash	Intermittent Coal Feed and Ash Removal, Sized Noncaking Coal, Thermal Efficiency Approx. 70%
Entrained	Koppers-Totzek	Commercial	850 (771)	Steam Oxygen	Dry Ash and Slag	Any Type of Coal Thermal Efficiency Approx. 77%
	Bi-Gas (BCR)	Pilot Plant	120 (109)	Steam Oxygen	Slag	Caking or Noncaking Coal
Fluid Bed	Winkler*	Commercial	100 (91)	Steam Oxygen	Dry Ash	Any Type of Coal, Thermal Efficiency Approx. 75%
	Hy-Gas (IGT)	Demonstration Pilot Plant	80 {73} 25 {23}	Hydrogen Steam & Oxygen	Dry Char Dry Ash	Lower Characters are for Steam-Process (Oxygen Plant Required) Slurry Feed
	CO-Acceptor (C&C)	Demonstration	30 (27)	Steam Air	Dry Ash	Oxygen Plant Not Required Lignite or Noncaking Coal
	Synthane (USBN)	Pilot Plant†	75 (68)	Steam Oxygen	Dry Char	Any Type of Coal
	Co-Gas	Pilot Plant	50 (45)	Steam	Dry Ash	Oxygen Plant Not Required
	Carbide-Battelle	Pilot Plant	25 (23)	Steam	Dry Ash	Oxygen Plant Not Required
	Hydrane (USBN)	Pilot Plant	0.25 (0.23)	Hydrogen	Dry Char	Caking or Noncaking Coal

\* These processes are classified under "Commercial" status because they are commercially applied. However, the methanation step required in every process to produce high-Btu gas has never been operated on a commercial scale.

Moving-Bed Process. Figure 19 shows the Lurgi process which uses a moving-bed reactor. A typical moving-bed gasification vessel is vertical and cylindrical in shape, has a water-jacket, and may have a diameter of up to 14 ft (4.3 m). Sized, noncaking coal is fed through air-lock hoppers at the top of the pressurized gasifier and is spread evenly over the entire reactor. Mixtures of steam and oxygen, introduced through a rotating grate at the bottom of the chamber, react with the coal to produce a raw gas comprised of:

<u>Component</u>	<u>Percent</u>
CO	21
H <sub>2</sub>	40
CH <sub>4</sub>	10
CO <sub>2</sub>	28
Other gases	1

The heating value of the raw gas is approximately 450 Btu/cu ft (16.8 MJ/m<sup>3</sup>) after the CO<sub>2</sub> is removed. This raw gas is further purified and methanated according to the reaction:



The final product has a heating value of approximately 950 Btu/cu ft (35.4 MJ/m<sup>3</sup>).

One of the major disadvantages of the Lurgi process is its requirement of noncaking (or very weakly caking) coals, which prohibits the use of coal mined east of the Mississippi River. These coals can be treated to make them noncaking, but the treatment is expensive. Efforts are under way to design a Lurgi gasifier which uses caking coal. In addition, low-temperature operation of the Lurgi gasifier releases coal volatile matter, including phenols and tars, into the product gas stream. The Lurgi process is primarily a batch process, but technology for continuous coal feed and ash removal is being developed.

Entrained-Bed Process. In the entrained-bed process, pulverized coal reacts with oxygen and steam at high temperatures (1700 to 2700°F [925 to 1480°C]) while the coal is suspended in the reactor. Due to the entrained coal, most of the ash leaves the gasifier with the raw product gas, but a portion is collected as slag at the bottom of the gasifier.

Entrained-bed processes can use any type of pulverized coal and cause fewer environmental problems, because the tars, phenols, light oils, and other volatile coal constituents collected during operation are never produced at high temperatures. The long-chain hydrocarbons are thermally cracked into short hydrocarbons such as methane.

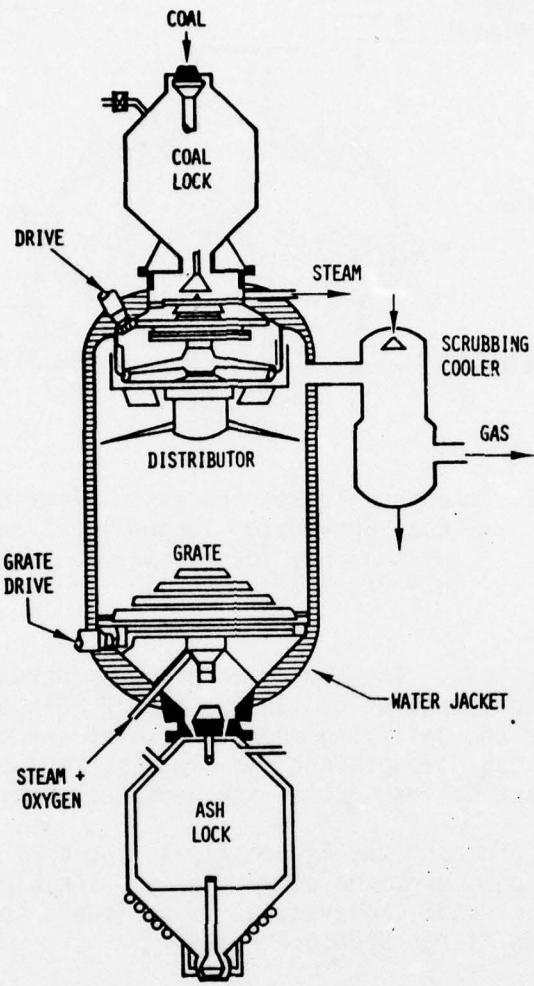


Figure 19. Lurgi gasifier. (From A. L. Conn, "Low Btu Gas for Power Plants," *Chemical Engineering Progress*, Vol 69, No. 12 [December 1973], p 56.)

Several processes that use this type of reactor have been developed. The Koppers-Totzek process (see Figure 20) has been operated on a commercial scale. The By-Gas process, developed by Bituminous Coal Research, Inc., will be tested on a 120 ton/day (109 Mg/day) pilot plant in the mid 1970s. A disadvantage of the Loppers-Totzek process is that low-pressure operation reduces the overall process economies, due to chemical equilibria considerations. This problem is solved in the By-Gas process, which operates at a pressure of 70 atmospheres (7.1 MPa).

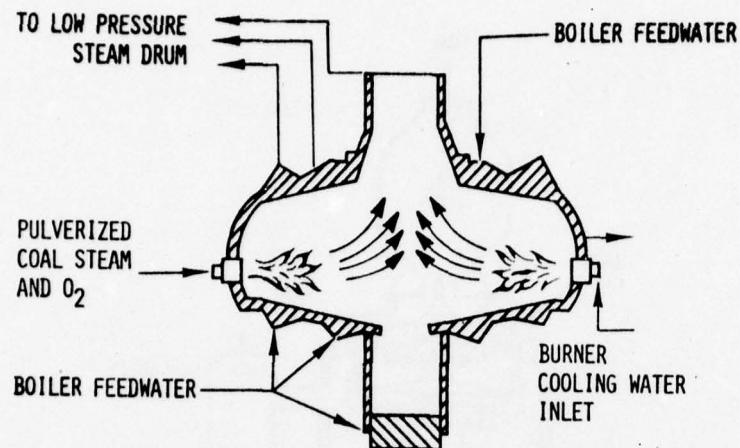


Figure 20. Koppers-Totzek process. (From H. Perry, "Coal Conversion Technology," *Chemical Engineering*, Vol 81, No. 15 [McGraw-Hill, July 22, 1974], p 92.)

Fluid-Bed Process. The fluid-bed process operates at atmospheric pressure and at temperatures of 1500 to 1850°F (815 to 1010°C). Oxygen and steam are the gasifying media. Most of the ash is carried out with the product gas. To prevent ash slagging, the product gas is cooled by a radiant boiler section in the upper portion of the gasifier.

The Winkler process (see Figure 21) is the only fluidized-bed process that has been operated commercially. The Winkler generator can handle all sizes of coal; however, it is difficult to use a strongly caking coal unless it has been pretreated.

The Hy-Gas process, developed by the Institute of Gas Technology (IGT) and the Hydrane process of the United States Bureau of Mines, uses a fluidized-bed hydrogasifier and a hydrogen generator. The hydrogasifier is operated in a counter-current fashion; coal is fed in from the top and hydrogen at the bottom. The coal is pretreated to form a slurry and is then reacted with hydrogen (produced from the hydrogen generator) at 1500 lb/sq in. (10.3 MPa) and 1700°F (927°C) to yield a high-Btu gas.

The CO<sub>2</sub>-Acceptor process developed by the Consolidation Coal Company, Inc., the Co-Gas process, and the Union Carbide-Battelle process do not require the expensive production and use of oxygen.

Construction of pilot plants for the Co-Gas process and the Union Carbide-Battelle process is nearing completion. In addition, large-scale pilot plants have been constructed under contract with the Office of Coal Research for the Hy-Gas and CO<sub>2</sub>-Acceptor processes.

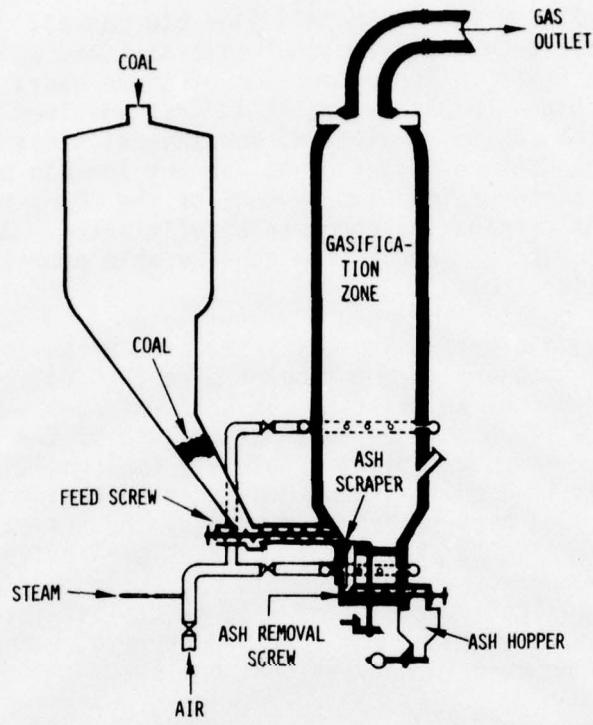


Figure 21. Winkler gasifier. (From H. Perry, "Coal Conversion Technology," *Chemical Engineering*, Vol 81, No. 15 [McGraw-Hill, July 22, 1974], p 57.)

In addition to the gasification processes outlined in Table 13, several other processes have been proposed, such as the Molten Salt process of the M. W. Kellogg Company, the Atgas reactor of the Applied Technology Corporation, and the Nuclear Coal Gasification process of Stone and Webster and Gulf-General Atomics.

All except the Lurgi, Koppers-Totzek, and the Winkler processes are still in the early stages of laboratory or pilot plant operation. The methanation step (see p 62) required in every process to make a high-Btu gas has never been operated on a commercial scale. Methanation catalysts are now under development, and their commercial demonstration should parallel the startup of commercial-scale gasification plants in this country.

#### *Low- and Medium-Btu Gasification*

Low- and medium-Btu gases are combustible gases having heating values of less than 500 Btu/cu ft ( $18.6 \text{ MJ/m}^3$ ) (medium-Btu gases) and

less than 200 Btu/cu ft ( $7.5 \text{ MJ/m}^3$ ) (low-Btu gases). Low-Btu gases are typically produced by gasifying coal with air, and medium-Btu gases by gasifying with oxygen. The production of these gases is similar to that used for high-Btu gases, but it is less involved and expensive. Gas purification can be simplified, and several steps can be eliminated. There is no need for an oxygen plant (in the low-Btu processes); in addition, shift conversion (improvement of the CO:H<sub>2</sub> ratio) is not required, and the methanation step can be eliminated. Because of these advantages, low-Btu processes show considerable promise as substitute sources of boiler fuels.

Since low- and medium-Btu gases are used as boiler fuels, they can be produced on-site and need not be of pipeline quality. If they are used in the boiler of an existing conventional steam-cycle power plant, boiler output will be reduced somewhat because of the fuel's lower heating value. For new power plants, however, coal gasification efficiency can be improved if used in a combined-cycle operation consisting of a gas turbine with a heat *recouper* powered by the hot exhaust gases of a gas turbine. While the thermal-efficiency level of the coal-gasification/combined-power-cycle operation is promising for future plants, the addition of gasification equipment will be capital-intensive. Medium-Btu gas, on the other hand, can be piped short distances to residential users, and can be used in conventional boilers.

There have been few developments in using air as an oxidant to produce low-Btu gas from coal. Only the Lurgi and Winkler processes have used air for full-scale gasification. Recently, however, attention has been given to developing low- and medium-Btu processes.

Table 14 summarizes gasification processes for low- and medium-Btu gas. Most high-Btu processes can be used to produce medium-Btu gas by eliminating the methanation step. However, many technical and design problems must be solved before low-Btu gas can be produced with minimal capital investment.

Moving-Bed Processes. An air-operated Lurgi gasifier has been operated intermittently for several years at a German power plant designed to use the produce gas in a combined gas-steam-turbine plant. The coal is gasified with 20 atmospheres (2 MPa) of air pressure. The product gases leave the gasifier at a temperature of approximately 1000°F (538°C) and are scrubbed to remove tar and dust. The gases are expanded in a turbine and then burned in a pressurized boiler. The exhaust gases from the boiler are again expanded in a gas turbine and used to heat the feedwater for the steam turbine. After modification to correct some design deficiencies, testing was resumed in late 1973 and is continuing.

Commonwealth Edison Company, in cooperation with the Electric Power Research Institute, is planning to construct an air-operated

Table 14  
Coal Gasification Process (Low- and Medium-Btu Gas)

Reactor Type	Process	Status	Capacity, Tons/Day (Mg/Day)	Gasifying Medium	Residue	Heating Value, Stu./cf (Mj/m <sup>3</sup> )	Remarks
Moving Bed	Lurgi (German)	Demonstration	2,000 (1814)	Steam Air or O <sub>2</sub>	Dry Ash	180 (6.7) (Air) 295 (11.0) (O <sub>2</sub> )	Sized Noncaking Coal
	Weillman-Galuska General Electric Slagging Bed	Pilot Plant	80 (73)	Steam Air	Dry Ash	168 (6.3)	Any Type of Coal
	Lab. & Design Commercial		0.25 (0.23)	Steam Air	Dry Ash		Any Type of Coal Continuous Feed
	Koppers-Roizek Bi-Gas (BCR)	Commercial (Europe)	850 (771)	Steam O <sub>2</sub>	Slag	300 (11.2)	Sized Coke or Char
Entrained Bed	Pilot Plant			Steam Air or O <sub>2</sub>	Slag	300 (11.2)	Any Type of Coal
	Combustion Engineering	Development & Design	120 (109)		Slag		
	Pittsburgh-Midway	Design & Construction	1,200 (1089)	Air	Slag	100 (100) (Btu)	100 Btu Unit (1976)
	Texaco	Pilot Plant		Oxygen (Air)			
Fluid Bed	Winkler CO <sub>2</sub> -Acceptor (CCC)	Commercial	2,000 (1814)	Steam Air	Dry Ash	300 (11.2) (O <sub>2</sub> ) 150 (5.6) (Air)	Any Type of Coal Proven with OII
	Demonstration		30 (27)	Steam Air	Dry Ash		Any Type of Coal
	Synthane (U.S.)	Pilot Plant & Design	75 (68)	Steam O <sub>2</sub> (or Air)	Dry Char & Ash	300 (11.2) (O <sub>2</sub> ) 180 (6.7) (Air)	Any Type of Coal
	Westinghouse	Pilot Plant	15 (14)	Steam O <sub>2</sub> (or Air)	Dry Ash	300 (11.2) (O <sub>2</sub> ) 150 (5.6) (Air)	Any Type of Coal
	IGI U-Gas (IGI)	Pilot Plant	70 (64)	Steam Air	Dry Ash		
	Battelle	Pilot Plant	25 (23)	Steam Air		Medium-Btu	Char and Coal

Lurgi gasifier, which would process 60 tons (54 Mg) of coal per hour to supply fuel for a 70-MW generating unit.

The Wellman Galusha and the General Electric processes are similar to the Lurgi process, but have additional advantageous features, such as continuous coal feed and operational capability with either caking or noncaking coal.

Entrained-Bed Processes. Low-Btu, entrained-bed processes can usually gasify both caking and noncaking, pulverized coals, and operate at temperatures high enough to remove ash in a molten state. The Koppers-Totzek process is the only commercially demonstrated process in this group. The Koppers-Totzek gasifiers have only been operated with oxygen and steam at atmospheric pressure to produce medium-Btu gas. Research is under way to develop a pressurized operation that uses air.

The By-Gas and Texaco Processes are under development and construction of pilot plants has begun. The Texaco process has been used extensively for oil gasification. This process has a unique coal-feed system; the coal is pulverized, slurried with water, and then pumped into the pressurized gasifier.

Entrained-bed processes of Combustion Engineering, Inc., Consolidated Edison Company, and Pittsburgh and Midway Coal Company are still being developed. These processes have been supported or cosponsored by the Office of Coal Research and several industrial consortia.

Fluid-Bed Processes. The Winkler gas generator is the only commercially proven process using air and a fluid-bed process to produce low-Btu gas.

The CO<sub>2</sub>-Acceptor process and the Battelle process do not require an oxygen plant to produce medium-Btu gas. This process uses an exothermic reaction of dolomite with CO<sub>2</sub> to furnish the heat required for gasification. The Battelle process has two steps. The coal is first burned with air in a fluidized bed under conditions that agglomerate the ash (gather it into a mass). The agglomerated ash then supplies the heat required to gasify the remaining char.

The Synthane (USBM) and the IGT processes are being tested on a pilot-plant scale. The processes produce high- and medium-Btu gas when using oxygen; similar processes using air are now being developed. The Westinghouse process consists of two fluid-bed gasifiers in series. The first devolatilizes, desulfurizes, and partially hydrogasifies the coal; the second produces the final gas. The fresh coal is prevented from caking by recycling large quantities of char and lime absorbent from the second vessel. When combustion takes place, the air temperature is high enough to agglomerate the ash and to furnish the heat for the process.

In addition to the low- and medium-Btu processes listed in Table 14, there are a few other processes being investigated, such as the Atgas process (Applied Technology Corporation), the Kellogg process (M. W. Kellogg Company), and a process developed by Atomic International. These processes are characterized by a molten bath gasifier that uses iron or sodium carbonate ( $\text{Na}_2\text{CO}_3$ ). The bath acts as a heat carrier to provide the heat required for the endothermic coal gasification.

A slagging-bed reactor has been investigated which operates at temperatures ranging from 2700°F to 3000°F (1480 to 1650°C)--high enough to keep the ash in a molten state. This process offers higher throughput than a nonslagging process. For more than 20 years, several slagging-bed gasifiers have been operated on a commercial scale with coke or char. Further development will be required to use coal, especially caking coal.

### 3 PETROLEUM FUELS

The principal liquid fuels are made by fractional distillation of petroleum (crude oil). Distillation separates the crude oil into gasoline, kerosene, gas oil, lubricating oil, and residual (these products are usually referred to as straight-run distillates and residuals). Thermal or catalytic cracking is used to convert kerosene, gas oil, or residual to gasoline, lower-boiling fractions, and a residual coke (cracked distillates and residuals). Catalytic processes are used to upgrade the various refinery intermediates into improved gasoline stocks or distillates. The major finished products are usually blends of a number of stocks, plus additives.

#### Characteristics of Fuel Oil

Fuel oil is defined (ASTM D288) as any liquid or liquefiable petroleum product burned for the generation of heat in a furnace or firebox, or for the generation of power in an engine, exclusive of oils with a flash point below 100°F (38°C) tag closed tester, and oils burned in cotton or woolwick burners. Fuel oils in common use fall into one of four classes: (1) residual fuel oils, which are topped crude petroleums or viscous residuums obtained in refinery operations; (2) distillate fuel oils, which are distillates derived directly or indirectly from crude petroleum; (3) crude petroleums and weathered crude petroleums of relatively low commercial value; and (4) blended fuels, which are mixtures of two or more of the three preceding classes.

Table 15 lists the standard fuel oil specifications (ASTM D396 and Federal Specification VV-F-815C<sup>11</sup>) which cover five grades of fuel oil limited by detailed requirements. The first column in the table describes each grade. The definition and significance of the other entries will be briefly discussed in the following paragraphs. Detailed laboratory procedures for petroleum fuel analyses are given by ASTM Standards.<sup>12</sup> Some of these standards are given in Table 16.

The flash point (ASTM D93 or D56) is the temperature to which oil must be heated to give off sufficient vapor to form an inflammable mixture with air. It is an indication of the maximum temperature at which the fuel can be stored and handled safely. It varies with apparatus and procedure, and both must be specified when stating the flash point. The minimum permissible flash point is usually regulated by law.

<sup>11</sup>Federal Specification VV-F-815C, *Specification for Burner Fuel Oil* (1972).

<sup>12</sup>1975 Annual Book of ASTM Standards, Parts 23, 24, 25, and 47 (ASTM, 1975).

Table 15

Detailed Requirements for Fuel Oils<sup>a\*</sup>  
 (From "Standard Specification for Fuel Oils,"  
 1975 Annual Book of ASTM Standards, ASTM D396-75,  
 Part 23 [ASTM, 1975], pp 219-220. Reprinted by permission  
 of the American Society for Testing and Materials, copyright.)

Grade of Fuel Oil	Flash Point, deg F. (deg C.)	Pour Point, deg F. (deg C.)	Water content, percent Max	Sediment, volume percent Max	Carbon Residue on 10 percent bottoms, percent Max	A.t.h. percent percent Max	Distillation Temperatures			Kinematic Viscosity, $\nu$ , cSt <sup>b</sup>			Copper Strip Corrosion No.			
							10 Percent Point		90 Percent Point		Universal at 100 F [38 C.]		Fuel at 122 F [50 C.]		At 122 F [50 C.]	
							Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
No. 1 A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel	100 or 105 (38) (38)	65 (-7)	0.05 [trace]	0.15	0.20 (15)	550 (288)			1.4 (37.9)	2.2 (37.9)			35	No. 3 0.5 or less		
No. 2 A distillate oil for general purpose heating for use in burners not re- quiring No. 1 fuel oil	100 or 105 (38) (38)	205 (-7)	0.05 [trace]	0.35	4 [282]	540 <sup>c</sup> (338)	640 (32.6)		2.25 (37.9)	3.6 (37.9)			30	0.5 or less		
No. 4 Propanating not usually required for handling or burning	130 or 135 (55) (55)	205 (-7)	0.50	0.10					45 (125)				5.8	26-49		
No. 5 (Liquefied propane) to be required depending on climate and equipment	130 or 135 (55) (55)		1.00	0.10					125 [150]	300			26-49 [32]	659		
No. 5 (Heavy) Propanating may be required for burning in cold climates, may be re- quired for handling	130 or 135 (55) (55)		1.00	0.10					300 [350]	900 [50]	40 [40]	65 [75]	649 [162]	(42) (81)		
No. 6 Propanating required for burning and handling	140 [150] <sup>d</sup> (60) [65] (65)			2.00 <sup>e</sup>					900 [900]	9000 [300]	-45 (-45)	(300)	>92	630 <sup>f</sup>		

\* Quantities enclosed in brackets denote values specified in Federal Specifications WFF-815C, which are different from ASTM specifications.

<sup>a</sup> It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next higher classification unless it meets all requirements of the lower grade.

<sup>b</sup> In commercial sales in the United States other sulfur limits may apply.

<sup>c</sup> Lower or higher viscosity values may be required whenever required by conditions of storage or use.

<sup>d</sup> The 10 percent distillation temperature shall be the minimum for use in other than atomizing burners.

<sup>e</sup> Viscosity values in parentheses are for information only and are not required for extraction.

<sup>f</sup> The amount of water by distillation plus the sediment by extraction shall not exceed 0.50 percent.

<sup>g</sup> The amount of water by distillation plus the sediment by extraction shall not exceed 0.50 percent. A deduction in quantity shall be made for all water and sediment in excess of 1.0 percent.

<sup>h</sup> The viscosity range of the initial shipment shall be identified and advance notice shall be given to the user to make the necessary adjustments.

<sup>i</sup> Where low sulfur fuel oil is required, the viscosity range of the initial shipment shall be identified and advance notice shall be given to the user to make the necessary adjustments.

<sup>j</sup> Where low sulfur fuel oil is required, the viscosity range of the initial shipment shall be identified and advance notice shall be given to the user to make the necessary adjustments.

<sup>k</sup> This notice shall be in sufficient time to permit the user to make the necessary adjustments.

<sup>l</sup> Low pour fuel oil should be used unless all tanks and lines are heated.

Table 16

**Selected ASTM Standards Relating to the Specifications  
and Testing Methods for Petroleum Fuels\***

*D 56 - 70 (1975) <sup>†</sup>	Test for Flash Point by Tag Closed Tester
*D 86 - 67 (1972)	Test for Distillation of Petroleum Products
*D 88 - 56 (1973)	Test for Saybolt Viscosity
*D 93 - 73	Test for Flash Point by Pensky-Martens Closed Tester
*D 95 - 70 (1975)	Test for Water in Petroleum Products and Bituminous Materials by Distillation
*D 97 - 66 (1971)	Test for Pour Point of Petroleum Oils
*D129 - 64 (1973)	Test for Sulfur in Petroleum Products by the Bomb Method
*D130 - 75	Test for Detection of Copper Corrosion from Petroleum Products by the Copper Strip Tarnish Test
*D240 - 72 (1973)	Test for Heat of Combustion of Liquid Hydrocarbon Fuels (General Bomb Method)
*D287 - 67 (1972)	Test for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)
*D288 - 61 (1973)	Def. of Terms Relating to Petroleum
*D396 - 75	Spec. for Fuel Oils
*D445 - 74	Test for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)
*D473 - 69 (1974)	Test for Sediment in Crude and Fuel Oils by Extraction
*D482 - 74	Test for Ash from Petroleum Products
*D524 - 64 (1973)	Test for Aniline Point and Mixed Aniline Point of Petroleum Products and Hydrocarbon Solvents
*D975 - 74	Specification for Diesel Fuel Oils
*D1250 - 56 (1973)	Petroleum Measurement Tables
*D1266 - 70 (1975)	Test for Sulfur in Petroleum Products (Lamp Method)
*D1551 - 68 (1973)	Test for Sulfur in Petroleum Oils (Quartz-Tube Method)
*D1552 - 64 (1973)	Test for Sulfur in Petroleum Products (High-Temperature Method)

\*Approved as American National Standard by the American National Standards Institute.

†D56 is the ASTM standard number; 70 (1970) is the year the standard originally was issued; number inside parentheses denotes the year the standard was reapproved without change.

Table 16 (Cont.)

*D1796 - 68 (1973)	Test for Water and Sediment in Crude Oils, and Fuel Oils by Centrifuge
*D2161 - 74	Conversion of Kinematic Viscosity to Saybolt Universal Viscosity or to Saybolt Furol Viscosity
*D2274 - 74	Test for Stability of Distillate Fuel Oil (Accelerated Method)
*D2500 - 66 (1971)	Test for Cloud Point of Petroleum Oils
*D2622 - 67 (1972)	Test for Sulfur in Petroleum Products (X-Ray Spectrographic Method)
*D2787 - 72	Test for Lead and Vanadium in Gas Turbine Fuels Test for Trace Metals in Gas Turbine Fuels (Atomic Absorption Method)
*D2880 - 71	Spec. for Gas Turbine Fuel Oils
*D613 - 65	Test for Ignition Quality of Diesel Fuels by the Cetane Method

The pour point (ASTM D97) is the lowest temperature at which oil will flow under prescribed conditions. Higher pour point oils may require heated storage and special handling facilities in cold climates.

Appreciable amounts of water and sediment in an oil tend to foul handling facilities and burning equipment. An oil's water and sediment content is determined concurrently by centrifuge (ASTM D1796), except for no. 6 oil, in which water is determined by distillation (ASTM D95) and sediment by extraction (ASTM D473).

Carbon residue (ASTM D524) is a measure of the carbonaceous material left after all the volatile components are vaporized in the absence of air. It indicates roughly the tendency of a fuel to form deposits in vaporizing burners, such as pot-type and sleeve-type burners, where the fuel is vaporized in an air-deficient environment.

Ash (ASTM D482) is the amount of noncombustible impurities. Depending on its composition, ash content may cause rapid deterioration of refractory materials in the combustion chamber of the abrasive destruction of handling equipment and burner parts.

Distillation temperature (ASTM D86) is an index of volatility. The test is significant for oils that will be burned on vaporizing- and atomizing-type burners. Hence, limits are only specified for no. 1 and no. 2 fuel oils. The limiting 10 percent value assures easy starting in burners, and the 90 percent limit excludes fractions that would be difficult to vaporize or atomize.

Viscosity (a measure of an oil's resistance to flow) indicates the relative ease with which an oil will flow or may be pumped and the ease of atomization. It is measured by either the Saybolt or the Kinematic viscosimeter. The Saybolt viscosimeter (ASTM D88) measures the time, in seconds, necessary for 60 cm<sup>3</sup> of fluid to flow through an orifice of specified diameter at specified temperatures between 70 and 210 °F (21.1 to 98.9°C). Two sizes of orifice are used: The Universal (0.0695 in. [1.765 mm]) and the Furol\* (0.1240 in. [37.795 mm]). The viscosity is expressed as Seconds Saybolt Universal (SSU) or Seconds Saybolt Furol (SSF). In general, the Saybolt Universal viscosimeter is used for low-viscosity oils (less than 1000 SSU) and the Saybolt Furol viscosimeter for heavier oils. The Kinematic viscosimeter (ASTM D445) measures the oil's resistance to flow under the influence of gravity. The unit of kinematic viscosity is the centistokes (cSt) which has the dimension (length)<sup>2</sup>/time. Viscosity decreases as temperature increases; hence, preheating high-viscosity oil may ease handling problems at normal or low temperatures.

\*The word Furol is a contraction of fuel and road oils.

The specific gravity of fuel oils is expressed arbitrarily on a scale termed "degree API."\* The relationship between API gravity and specific gravity is given by the expression:

$$\text{Degrees API} = (141.5/d) - 131.5 \quad [\text{Eq } 8]$$

where  $d$  is the specific gravity at 60/60°F (the ratio between the density of oil at 60°F [15°C] and water at 60°F [15°C].

API gravity is determined by hydrometer (ASTM D287). The API gravity of pure water at 60°F (15°C) is 10 degrees. The range of fuel oils is approximately 10 to 40° API. The API gravity is used to determine weight-volume relationships and to calculate the heating value of oil (see Eq 10).

The corrosion test (ASTM D130) serves to indicate the presence of materials in no. 1 fuel that might corrode copper, brass, and bronze components of the fuel system.

A limited amount of sulfur content may be required for special processes in connection with heat treatment, nonferrous metal, glass, or ceramic furnaces. Also, Federal, state, or local legislation or regulations limit the amount of sulfur content. Sulfur content may be determined by any of the following methods: bomb method (ASTM D129), quartz tube method (D1551), high temperature method (D1552) or the X-ray spectrographic method (D2622). In addition, the lamp method (D1266) may be used for no. 1 fuel.

The heating value of fuel oil is determined by the bomb calorimeter method (ASTM D240) and may be approximated by the following formula:

$$Q_h = 22320 - 2780d^2 \quad [\text{Eq } 9]$$

$$\text{or } Q_h = 22320 - 7.568 \times 10^7 / (\text{°API} + 131.5)^2 \quad [\text{Eq } 10]$$

where  $Q_h$  is the higher heating value in Btu/lb. The lower heating value  $Q_l$  may be calculated by the expression:

$$Q_l = Q_h - 90.8H \quad [\text{Eq } 11]$$

where  $H$  is the weight percentage of hydrogen and can be obtained from the relation:

$$H = 26 - 15d \quad [\text{Eq } 12]$$

\*American Petroleum Institute.

The specific heat of oil at temperature  $t$  ( $^{\circ}$ F) can be approximated by:

$$c = (0.388 + 0.00045t)/\sqrt{d} \quad [\text{Eq } 13]$$

### Transportation

There are four primary means of transporting fuel oil: road, rail, water, and pipeline. The method used may be determined by location, unloading and storage facilities, distance, and the cost of transport.

#### *Road*

Although truck transport of fuel oil is comparable in scale to rail transport, it is used more widely. Load limits are regulated on a per-axle basis and are stricter than rail regulations. Trailers generally have a capacity of about 4000 to 5000 gal (15 to 19 m<sup>3</sup>) with some allowance for expansion. Some trailers are equipped with heaters for high-viscosity oils; others are used solely for gasoline and light oils. The advantages of truck over rail transport are ease and directness of delivery.

#### *Rail*

Rail delivery is generally used for the final transporting of oil from the storage terminal or refinery. Costs are more dependent on distance than quantity.

Tank cars usually have a capacity of 100 tons (91 Mg) but may be as small as 40 tons (36 Mg). Load regulations limit the maximum amount of oil permitted in a car. Cars are equipped with heaters to maintain viscosity during transit and unloading.

#### *Water*

Water transport varies from small river barges to huge supertankers. Barges are usually loaded with only one grade of oil, but large tankers may carry as many as eight grades in separate compartments. The capacity of these tankers ranges from 10,000 to nearly 300,000 dead-weight tons (DWT) (9.1 to 272 Tg). Barges are limited to inland waterways and have capacities of 300,000 gal (1136 m<sup>3</sup>).

Water transportation costs are low and generally decrease with increasing quantity of shipment. The purchaser must supply unloading equipment and storage facilities, unless he/she is buying from a commercial refinery.

### *Pipelines*

Pipelines are widely used to transport crude and refined oil products and are the least expensive oil delivery method. Pipe delivery is more convenient than water transport since it is independent of natural transportation networks.

Oil pipes are generally steel, butt-welded fixtures, coated with either tape or enamel to protect against underground corrosion. Long pipelines use cathodic protection to maintain a minimum negative potential with respect to ground in order to reduce cathodic corrosion. Semi-annual checks establish weak points and indicate where additional protection is necessary.

Crude oil pipelines generally transport oil at elevated temperatures and require thermal insulation. Separating different grades of oil for transporting is usually done on a quantity (metered) basis, since mixing of crude grades is usually not critical. When possible mixing is critical, changes in specific gravity are used to determine switch-off points to avoid interfacial mixing.

Multiproduct pipelines require a sensitive switching system. The products, such as kerosene, gasoline, and low-viscosity oils, are piped in a definite sequence, and switching into the appropriate tanks is by detection of changes in viscosity or specific gravity.

Estimating the cost of piped fuel oil is difficult; however, it is important to remember that transportation costs are affected very little by distance, but are greatly dependent on quantity. Buying in large quantities is much more economical for any fixed distance, if the required storage volume is available at the plant site.

### *Volume Corrections*

Fuel oils are sold by volume, i.e., in gallons or in 42-gal (.16-m<sup>3</sup>) barrels. Since volume varies with temperature changes, volume readings are corrected to a standard reference temperature of 60°F (15°C) for many commercial transactions. ASTM-IP\* Petroleum Measurement Tables (ASTM D1250 or IP 200/52) can be used for this purpose. Table 17 gives the volume correction factor for different groups of oil at various observed temperatures. This factor, when multiplied by the volume of oil at the given temperature, results in the volume at 60°F (15°C). It is important to note that the group classification is determined by the API gravity at 60°F (15°C). The first part of Table 17 gives the group classification and its corresponding range of API gravity at 60°F (15°C).

\*Institute of Petroleum.

Table 17

Volume Correction Table for Fuel Oils  
 (Metric Conversion Factor:  $^{\circ}\text{C} = [{}^{\circ}\text{F}-32]/1.8$ ).  
 (From *Standard Petroleum Measurement Tables*, ASTM D1250-56  
 [ASTM] Reprinted by permission of the American Society for  
 Testing and Materials, copyright.)

Group No.	Range of Group, API Gravity 60°F	Coefficient of Expansion per °F, at 60°F	Corresponding API Gravity 60°F
0	0 to 14.9	0.00035	6.0
1	15.0 to 34.9	0.00040	22.0
2	35.0 to 50.9	0.00050	44.0
3*	51.0 to 63.9	0.00060	58.0
4	64.0 to 78.9	0.00070	72.0
5	79.0 to 88.9	0.00080	86.0
6	89.0 to 93.9	0.00085	91.0
7	94.0 to 100.0	0.00090	97.0

Observed Tempera- ture, °F	Group Number and API Gravity Range at 60°F		
	Group 0 0-14.9° API	Group 1 15.0-34.9° API	Group 2 35.0-50.9° API
	Factor for Reducing Volume to 60°F		
0	1.0211	1.0241	1.0298
10	1.0176	1.0201	1.0248
20	1.0141	1.0160	1.0199
30	1.0105	1.0120	1.0149
40	1.0070	1.0080	1.0099
50	1.0035	1.0040	1.0050
60	1.0000	1.0000	1.0000
70	0.9965	0.9960	0.9950
80	0.9930	0.9921	0.9901
90	0.9896	0.9881	0.9851
100	0.9861	0.9842	0.9801
110	0.9826	0.9803	0.9751
120	0.9792	0.9763	0.9702
130	0.9758	0.9725	0.9652
140	0.9723	0.9686	0.9602
150	0.9689	0.9647	0.9552
160	0.9655	0.9609	0.9502
170	0.9621	0.9570	0.9452

Table 17 (Cont.)

Observed Tempera- ture, °F	Group Number and API Gravity Range at 60°F		
	Group 0 0-14.9° API	Group 1 15.0-34.9° API	Group 2 35.0-50.9° API
	Factor for Reducing Volume to 60°F		
180	0.9587	0.9532	0.9403
190	0.9553	0.9494	0.9353
200	0.9520	0.9456	0.9303
210	0.9486	0.9418	0.9253
220	0.9452	0.9380	0.9203
230	0.9419	0.9343	0.9153
240	0.9385	0.9305	0.9103
250	0.9352	0.9268	0.9053

### Storage of Petroleum Fuel

A number of factors govern the choice of a fuel oil storage facility, which may be either above or below ground. Other considerations, such as cleaning, sampling, and metering, will also influence the choice of storage facility and its construction.

#### *Choice of Facilities*

Five primary criteria must be considered when selecting storage facilities: the area's geophysical characteristics; applicable storage regulations; local temperature range; accessibility; and space available for storage.

Local soil and water conditions are important considerations when specifying tank material and construction, e.g., a full 25,000-gal (94.6-m<sup>3</sup>) tank weighs about 120 tons (109 Mg); hence, proper ground support is essential. Insufficient support requires additional foundation work before installation. Most tanks are constructed of welded steel plates that are subject to corrosion and structural weakening when exposed to air and water. Although steel tanks are coated with a protective paint or resin, an underground facility should be placed well above the water table.

Engineering-based safety standards for fuel oil storage should be observed during the initial design stages. Specifications that pertain to grounding, welded joints, gauging, and failure precautions are available from the Underwriters Laboratory<sup>13-15</sup> and the American Petroleum Institute.<sup>16,17</sup> Requirements for safe storage and usage of fuel oil are given in the National Fire Codes.<sup>18,19</sup> State and local governmental agencies may also have applicable regulations.

Extremes in local temperature are the single most prevalent source of combustion problems and system failures. Oils with high pour points

<sup>13</sup>Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids, UL 142 (Underwriters Laboratories, Inc., 1968).

<sup>14</sup>Standard for Steel Underground Tanks for Flammable and Combustible Liquids, UL 80 (Underwriters Laboratories, Inc., 1968).

<sup>15</sup>Standard for Steel Inside Tanks for Oil Burner Fuel, UL 80 (Underwriters Laboratories, Inc., 1968).

<sup>16</sup>Oil Storage Tanks With Riveted Shells, Standard No. 12A, 7th ed. (American Petroleum Institute [API], 1951).

<sup>17</sup>Welded Steel Tanks for Oil Storage, Standard No. 650, 5th ed. (API, 1973).

<sup>18</sup>Flammable and Combustible Liquids Code, NFPA No. 30-1973 (National Fire Protection Association [NFPA], 1973).

<sup>19</sup>Standard for the Installation of Oil Burning Equipment, NFPA No. 31-1974 (NFPA, 1974).

need tank heaters, especially during the colder seasons. Some low-viscosity oils tend to vaporize at high temperatures and cause inefficient combustion of fuel.

Access to the inside of the tank is essential for cleaning and sampling. Larger tanks have two means of access: a small hole for gauging oil depth and a larger manhole for cleaning and sampling. Many installations neglect cleaning and seal the manhole either by letting it rust shut, or by cementing over the top. Oil cannot be sampled through the gauge port, nor can cleaning be accomplished efficiently by opening a drain plug in the bottom or by dropping in a hose from the top.

Efficient space use is important to any industrial layout. The consumer must evaluate tank location in terms of individual proximity requirements, aesthetic values, and code requirements.

#### *Underground Tanks*

Underground tanks are usually limited to 50,000 gal ( $190\text{ m}^3$ ); smaller tanks may be constructed of solid steel, and larger tanks of welded steel plates. Although the tanks are already painted, they should be further protected against corrosion with a thick, hot, bituministic coating. Underground tanks are mounted a few degrees from the horizontal and anchored either to ground or concrete. All tanks are fitted with a drain valve on the low end, a filler and gauge opening, a breather pipe, and an outlet pipe. If the tank is buried (instead of being submerged in a compartment), some method of drainage must be fitted to the drain plug and the tank heavily anchored to prevent it from floating when empty.

The breather pipe should have a self-draining trap to remove condensation and a collection device to contain hydrocarbon vapor emissions. The outlet or take-off pipe should join the tank at 4 to 6 in. (100 to 180 mm) from the bottom to avoid water and sludge escape. An accessible filter should also be installed on the outlet pipe to trap unwanted sludge.

Underground storage of fuel oil is presently the most common method, which has the advantages of saving space, providing a more pleasing appearance, and reducing fire hazards. In addition, underground storage tanks have been successfully built over and landscaped. The major disadvantages of underground storage are more rapid corrosion from moisture, greater costs, and stricter construction standards.

#### *Aboveground Tanks*

The cleaning and venting of aboveground tanks is similar to that of underground facilities. Doors or manholes, drain plugs, and gauges are much more accessible. Tanks should be constructed of either steel

or concrete and should be coated to prevent corrosion. Support stanchions and foundations should be installed where necessary or as specified by the manufacturer. Since fire and tank failure are more critical with these tanks, a retaining or dike wall must be constructed to act as a pool having larger capacity than the tank; in the event of tank failure, the oil would escape to this pool, but no further.

#### *Tank Heating*

Preheating fuel oil to facilitate transport and combustion is a common practice at most fuel-burning installations using heavy oils. Preheating reduces the viscosity of heavy oils and permits unblocked flow through the feed system; it also causes oil to burn more efficiently by entering the burner at a temperature close to its flash point. A realistic preheating system approaches these criteria equally; however, care must be taken to prevent a reaction similar to thermal cracking, caused by overheating the fuel. This would form a light, low-Btu fluid and a dense residual which might foul the burner mechanism. On the other hand, heating the oil to just below the flash point could cause the oil to be too viscous for proper feeding. This is especially critical when burning crude oil or high-viscosity no. 6 oils. Additional problems occur when trying to atomize thick oils for combustion.

For good combustion, a certain viscosity must first be maintained; the appropriate preheat temperature is then found either by experimentation or by reference to a viscosity-temperature chart (e.g., ASTM D341). In cases where the appropriate temperature approaches the flash point, the viscosity usually takes precedence; however, preheating should be approached cautiously, since a temperature increase decreases the oil's volume-based heating value; i.e., the volumetric-flow rate must be increased to maintain the same boiler-output. The amount of heat required to preheat the oil from  $t_1$  to  $t_2$  ( $^{\circ}$ F) is determined by

$$q = c(t_2 - t_1) \quad [\text{Eq } 14]$$

where  $q$  is the Btu/lb and  $c$  is the average specific heat, i.e., the average of the specific heats at  $t_1$  and  $t_2$ , respectively.

The specific heat can be calculated by Eq 13 or taken from tables. Table 18 lists the specific heat of oils at different gravities and temperatures.

Currently, tanks are usually heated by steam, especially in larger storage facilities. The most popular devices are helical coils, grid-type heaters, and submerged shell and tube heaters. Steam is used more frequently because it is readily available from oil-fired boilers, but electric heaters are used when the cost of steam is prohibitive.

Table 18

Specific Heat of Fuel Oils\*  
 (From *Miscellaneous Publication No. 97*  
 [National Bureau of Standards, 1929])

Temp. deg. F	Degrees API at 60°F (15°C)			
	10	20	30	40
	Specific Heat, Btu per Pound			
40	0.406	0.420	0.434	0.447
60	0.416	0.429	0.443	0.457
80	0.424	0.439	0.453	0.467
100	0.433	0.448	0.463	0.477
120	0.442	0.457	0.472	0.487
140	0.451	0.467	0.482	0.497
160	0.460	0.476	0.491	0.506
180	0.469	0.485	0.501	0.516
200	0.478	0.495	0.511	0.526
220	0.487	0.504	0.520	0.536
240	0.496	0.513	0.530	0.546
260	0.505	0.523	0.540	0.556
280	0.514	0.532	0.549	0.566
300	0.523	0.541	0.559	0.576

---

\* Conversion formulas:

$$^{\circ}\text{C} = (\text{°F}-32)/1.8$$

$$1 \text{ Btu/lb} = 2.326 \text{ kJ/kg}$$

Steam coils in a helical array are common in older oil tanks. The coil is placed near the bottom of the tank and is fed by the boiler, or in some cases, by an auxiliary steam system. Some steam systems are equipped with electric coils for high-viscosity startup. Helical coils are inefficient, always heating the entire tank when steam demand may sometimes be as low as 1 percent of boiler production.

Grid heaters are operated by electrical power and are restricted to small tanks; however, their use is inefficient because the whole tank is heated. Submerged shell and tube-type heaters use a steam-fed heater tube that is smaller than the conventional helical coil, and a cylindrical shell which surrounds the tube. The shell retards heat conduction to the rest of the tank, thus providing a more efficient, localized heating.

#### *Additional Considerations*

Since routine maintenance of a storage facility is essential to efficient system operation, cleaning, sampling, and metering ease are important design considerations.

Sludge accumulation is usually an unavoidable problem. Suspended particles may often be precipitated when new oil is added. Sludge can usually be removed by washing, which requires both access to the tank interior and a strong solvent to insure proper agglomerate breakup. The sludge is drained off at the tank's lower end.

Filters should be installed at the outlet to trap suspended particles and sludge. Most particles are suspended, due to agitation of the bottom sludge. Since outlet pipes are located near the tank base, the difficulties may be multiplied by high volumes of consumption. Filtering elements should be changed frequently.

Gauges to measure tank contents or meters to measure outflow are essential bookkeeping devices. Gauges usually indicate the depth of oil in a tank, and the volume can then be determined from a calibration chart. Figure 22 can be used to estimate the volume for different size tanks when the oil depth is known. Outflow meters are more reliable than gauges but require more care. The most important metering problem is the expansion and contraction of oil from temperature fluctuations (see Table 17 for the coefficients of thermal expansion for different groups of oil).

Tank water is a common problem. Since water settles to the bottom, it usually can be removed through the drain spout.

#### Blending

Most fuel oils received by the consumer are a mixture or blend of two or more oil grades. The purpose of blending is to generate an oil

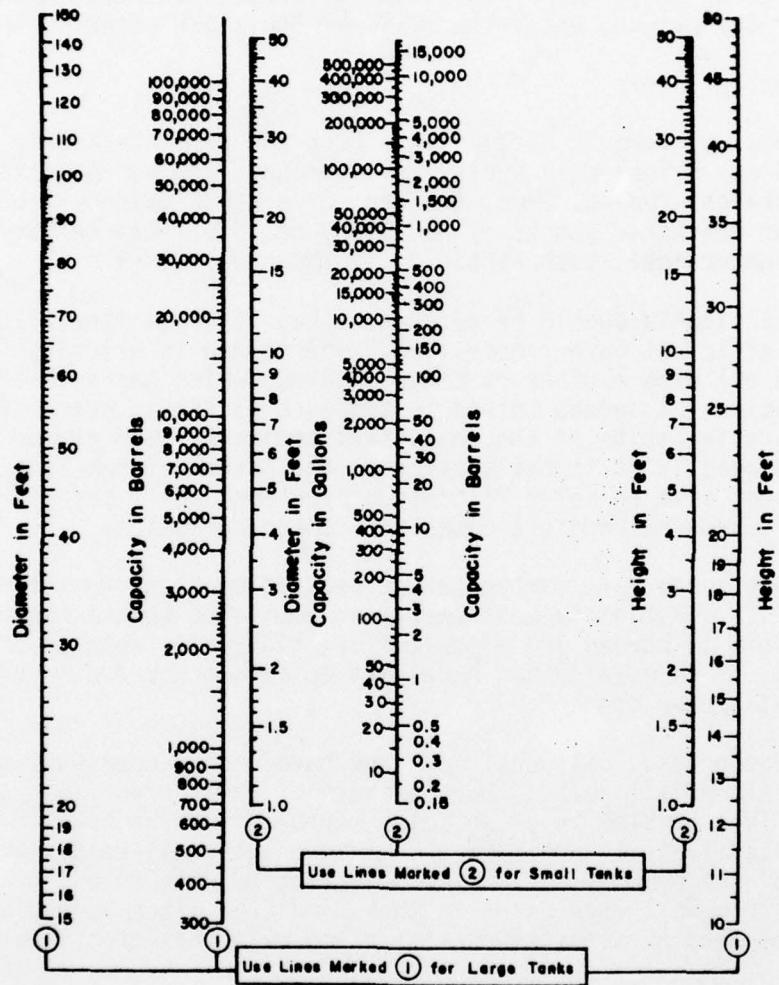


Figure 22. Nomograph for determining vertical-cylindrical tank capacity.  
 (Metric Conversion Factors: 1 ft = 0.3048 m; 1 gal = 3.785  $\times 10^{-3}$  m<sup>3</sup>; and, 1 barrel = 0.159 m<sup>3</sup>.) (From P. F. Schmidt, *Fuel Oil Manual*, 3rd ed. [Industrial Press, Inc., 1969], p 228. Copyright by Industrial Press, Inc. Reprinted with permission.)

which satisfied the user's particular combustion and handling requirements. Blending may be used to reduce the viscosity or pour point of a thick oil, reduce the amount of bottom sediment and water (sometimes referred to as BSW), reduce the level of undesirable contaminants such as sulfur and carbon, and raise or lower the flash point.

#### *Objectives*

Plants may find it difficult to burn and pump the highly viscous no. 5 and no. 6 fuel oils during cold weather. Common practice is to burn a straight-run no. 2/no. 6 blend, or a crude oil/no. 6 blend during colder weather. Stocks of no. 5 and no. 6 oil may be cut or reduced with a lighter fuel, such as no. 2, in the user's tank.

Excessive BSW should be reduced, since it clogs line filters and disrupts efficient burner operation. One method is diluting the contaminated oil with another of the same grade which has a lower BSW concentration. A second method is adding a different grade of oil to promote precipitation of the emulsified sediment. BSW can be dealt with more readily if it has settled to the bottom of the tank. Dilution is best used to solve filtration problems, while precipitation is best for improving an oil's combustion characteristics.

Excess sulfur and carbon can be reduced by blending with low-sulfur oil. Dilution is most easily accomplished when a heavy no. 5 or no. 6 oil is burned and a low-sulfur, light oil, such as a no. 2, is added. It is usually not necessary to dilute no. 2 oil to reduce sulfur and carbon content.

Although heavy oils cost less and have higher heating values, they are often difficult to burn because of their high flash and fire points. This problem is often solved by blending the heavier oils with a light distillate to increase the mixture's overall volatility; this was one of the primary reasons for creating no. 4 fuel oil. Care must be taken, however, when using in-tank blending, since widely different oil grades tend to separate no matter how well they are blended.

#### *Techniques*

Blending is generally done at the supplier's facilities or at the refinery because of high equipment costs and space requirements. Most suppliers carry only the basic grades of oil and blend them to meet customer needs and specifications. Blending can be done in the supplier's equipment, tank cars, trucks, or even the consumer's own storage tank. The most common methods of blending are heating, agitation, circulation, gravitation, and proportioning pumps and meters.

Heating by itself is not a blending technique, but is used to simplify other blending methods. Heat causes oil circulation and can be especially helpful for blending high-viscosity fuels. Typical mixing

temperatures range between 120° and 180°F (49° to 82°C), depending on the viscosity and flash points of the fuels being blended.

Agitation equipment uses a blade and motor to stir tank contents. The resulting mixture is somewhat unstable, even when heat is used; its use is limited to situations in which the fuel will be used quickly, such as a day tank. Some consumers use agitation in their own tanks to prevent blended oils from separating, but agitation is usually employed by the supplier, since specialized equipment is needed.

Circulation pumps a proportional mixture of oil grades out, around, and back into the tank. Typical circulation systems are heated, with flow from the bottom to the top of the tank.

Gravity blending is a poor, but widely used mixing method. The difference in density between the components promotes mixing by one of two methods. In the first case, heavy oil pumped into the top of the tank of light oil mixes as it settles to the bottom. In the second case, light oil is added to the bottom of the tank and mixes with the heavy oil as it rises. This method, used widely with trucks or tank cars before delivery, especially when more thorough blending facilities are not available, produces the least stable blends.

Proportioning pumps and meters provide good blends, but require complicated system designs and have high equipment costs. In this technique, heated quantities of the desired blending grades are pumped at predetermined rates into a larger common pipe and mixed as they flow into the tank.

#### Additives

Fuel oil contains varying amounts of noncombustible ash and sulfur which foul the burner and boiler and cause high combustion temperatures. The ash and sulfur compounds may adhere to metal boiler surfaces, catalyzing surface oxidation and forming strong acids which rapidly corrode the metal. They can also form thick deposits on boiler tubes and reduce heat transfer.

Four general methods will alleviate these problems: (1) catalysis can be retarded by lowering the superheat temperature; (2) ash and sulfur can be removed before combustion; (3) the oil can be burned with less excess air than in a "normal" firing; or (4) additives can be used to neutralize the acid or prevent catalyst formation.

Lowering the superheat temperature is the least desirable alternative, but is an applicable technique for low- and medium-pressure boilers.

Removing extraneous ash, sulfur, and carbon from fuel oil is difficult and expensive, since this causes excessive fuel loss.

Reducing the excess air level will reduce the oxidation potential of the fuel and its contaminants. Most high-volume burners are adjusted to minimize stack heat loss while maximizing fuel efficiency. Reducing excess air will decrease stack losses, but may promote incomplete fuel burning.

Using an appropriate oil additive will solve many of the corrosion problems without altering the burner operation. Additives typically function in one of two ways: (1) they can either prevent oxidation of the catalysts, causing them to remain inert and be carried off by exhaust gases and soot; or (2) they can promote the formation of large, inert particles which capture the catalysts and carry them out of the stack or adhere to the stack and boiler tubes where they can be removed by cleaning.

#### Sampling Storage Tanks

Sampling is used to diagnose trouble and to determine blending results, degree of stratification, amount of bottom sludge, and water level. A composite sample is the best means of determining oil stratification. Obtaining samples from various levels, usually at 1-ft (.3-m) intervals, gives a good representation of the tank contents and provides for testing sludge suspensions at lower levels.

If sludge accumulation is a particular concern, a bottom sample can be taken. The sample location must be chosen carefully, since sludge accumulation increases in relation to the distance from the point of oil discharge into the tank.

Presence of bottom water may be determined by using a dip stick coated with some "water-detecting paste." When immersed in the tank, the stick will turn red when exposed to areas where water is present. An oil-water emulsion will be indicated by red spots, and a bottom layer of water by a solid red.

Operating difficulties may be traced to any of the above maintenance problems. An additional test for contaminants involves analysis of the filter deposits. Careful analysis of material accumulated on the fuel filter can pinpoint both the origin and concentration of the pollutant, as well as the quality of the oil going to the burner.

#### Combustion

The combustion segment of a fuel oil system is its most important and complex part. There are numerous types of oil burners, and each is suited for different heat release requirements and oil grades;

however, any burner must satisfy specific requirements in five areas: fuel flow, fuel cleaning, vaporization or atomization, ignition, and fuel-air ratio control. Efficient use of fuel oil and the system's longevity depend on how these combustion requirements are met.

Free flow of fuel oil from tank to burner is an essential consideration. When the oil leaves the heated tank, its temperature may fall below its pour point while en route to the combustion equipment because of long feed lines and/or low ambient temperatures. Line heaters, which are either steam or electric coils, are used to sustain free flow; steam coils are more prevalent because of the availability of steam from the boiler. The coils may surround the entire pipe length, but most viscous flow systems use coils only at regular intervals. Many steam systems use a small electric resistance coil jacket when startup is difficult. Typical oil-line heating systems are expensive, but they are able to use low-cost residual oils that other systems cannot use. Distillate and blended oils do not usually present flow problems.

Clean oil is essential to both efficient combustion and maintenance of a clean burner. Suspended contaminants may consist of sludge stirred up from the tank bottom, suspended foreign matter, or scale from the tank or pipe walls. If these particles reach the burner, they will either clog the burner passages or form soot which will be deposited on the burner walls. Preventing these problems is best accomplished by filters at the tank outlet and throughout the feed system. The choice of filter size depends on the particular oil-handling system and the oil grade being used. Filters should be cleaned or changed periodically to avoid restricting the oil flow.

When the oil reaches the combustion point, it must be converted into a state to enhance combustion. Burner mechanisms exist principally to convert the nonvolatile liquid oil into a vapor or aerosol state for ignition. While distillate oils vaporize at just above room temperature, most high-viscosity oils have high boiling points. Since a high temperature may cause thermal cracking or the separation of blended oils, heavy-oil burners use an atomizer to convert the viscous liquid to a combustible aerosol. The three most common aerosol mechanisms are high-pressure nozzles, directed air jets, and rotating discs. Proper atomizing increases the oil's surface area, making it more conducive to evaporation. Improper atomization will waste fuel and cause carbon deposits throughout the burner system.

Igniting the vaporized or atomized oil is generally accomplished with an electric arc. Ignition systems vary with facility size and the manufacturer, but high-volume ignition generally employs a 10,000-V potential across a 3/16-in. (4.8-mm) spark gap. The spark is generated in front of the spray nozzle or cone; the distance of the spark from the spray nozzle tip should vary inversely with the angle in which the oil spray is expelled. For example, a spray cone of 80 degrees

should be sparked directly in front of the nozzle, while a smaller cone should be ignited some distance from the nozzle. Oil should not touch the electrode, since carbon deposits will form and inhibit sparking; however, the spark should be close enough to burn the oil particles completely. Routine burner maintenance should include checking the electrode to remove carbon buildup and maintaining a blunt electrode tip to avoid overheating and provide a larger spark-receiving surface.

Regulating the air supply is critical to combustion sequence. The burner supplies primary air for atomization and combustion, either through a separate spray nozzle or from the oil nozzle. Secondary air flows into the combustion chamber through vents and serves to carry off exhaust gases. The control of these two quantities of air, especially the primary flow, is important to economical and efficient combustion. Too much primary air may push the oil past the spark or blow out the flame, both of which waste large quantities of oil. An air deficiency will promote incomplete combustion and waste fuel. Both of these extremes can be avoided by periodically "tuning" the combustion system according to the manufacturer's specifications and the design conditions.

#### Burners

The term "oil burner" refers to the entire combustion mechanism, including both the atomizing and ignition devices. Choice of a particular burner depends primarily on the type and volume of oil to be burned. Of all the burner types available, only four apply to larger industrial applications: rotating-cup burners, mechanical atomizing burners, high-pressure steam/air atomizing burners, and low-pressure steam/air atomizing burners (see Table 19). All four systems use the spark ignition system described previously. Oil may be atomized mechanically before expulsion into the combustion chamber, or by expanding an emulsion of oil and compressed air or steam in the chamber itself.

The rotating-cup burner (Figure 23a)--the most economical of all industrial burners--may burn any grade of fuel oil if the oil is pre-heated. Oil flows through a hollow feed tube to a cup mounted on a rotating shaft, which is moved at speeds from 3600 to 10,000 rpm by an electric motor or air turbine. Atomization occurs when the oil is flung from the cup's rim. A fan attached to the shaft supplies primary air, which is directed to jets next to the cup edge. Jet angles are adjusted to accommodate fuel feed. Rotating-cup burners use both electric and gas ignition, and larger models may be equipped with hand starters. Vertical and horizontal feeds are available; however, vertical atomizers are generally used only for light oils. Secondary air accounts for 85 percent of the theoretical air requirement, and is supplied through natural draft vents. Power requirements are low, and oil feeds of up to 200 gal (.76 m<sup>3</sup>) per hour are available.

Table 19  
Commercial Oil Burners

Burner Type	Method of atomization	Fuel	Usual ranges of pressures, psi (kPa)	Atomizing Medium gph	Usual range of burner capacity,* gpm (cm <sup>3</sup> /s)	Fuel grade	Oil-heating temp. °F (°C)	Ignition	Control
Horizontal-rotary	Rotating cup	-1 to 50 (6.9 to 344.7)			5-200 (5.3-210)	No. 5 No. 6	Room temp. 170 (76.7)	Manual or electric-gas	Intermittent or variable flame, or both
Low-pressure-air	Nozzle	Up to 15 (103.4)	0.5- (3.4 - 17.2)	2.5 (3.2-105)	No. 5 No. 6	Room temp. 170 (76.7)	Manual or electric-gas	Intermittent or variable flame, or both	
Medium-pressure-air	Nozzle	Up to 25 (172.4)	5 - 25 (34.5-172.4)	10-75 (10.5 - 78.9)	No. 5 No. 6	Room temp. 170 (76.7)	Manual or electric-gas	Intermittent or variable flame, or both	
High-pressure-air	Nozzle	Up to 100 (689.5)	50 - 100 (344.7 to 689.5)	15-100 (15.8-105)	No. 5	Room temp.	Manual	Variable flame	
Steam atomizing	Nozzle	Up to 100 (689.5)	50 - 100 (344.7 to 689.5)	15-100 (15.8-105)	No. 6	180 (82.2)	Manual	Manual	
Mechanical-pressure atomizing	Orifice in tip	75-300 (517.1 to 2068.4)		50-200 (52.6-210)	No. 6	300 (148.9)	Manual	Variable flame	

\* From minimum rate of smallest size to maximum rate of largest size.

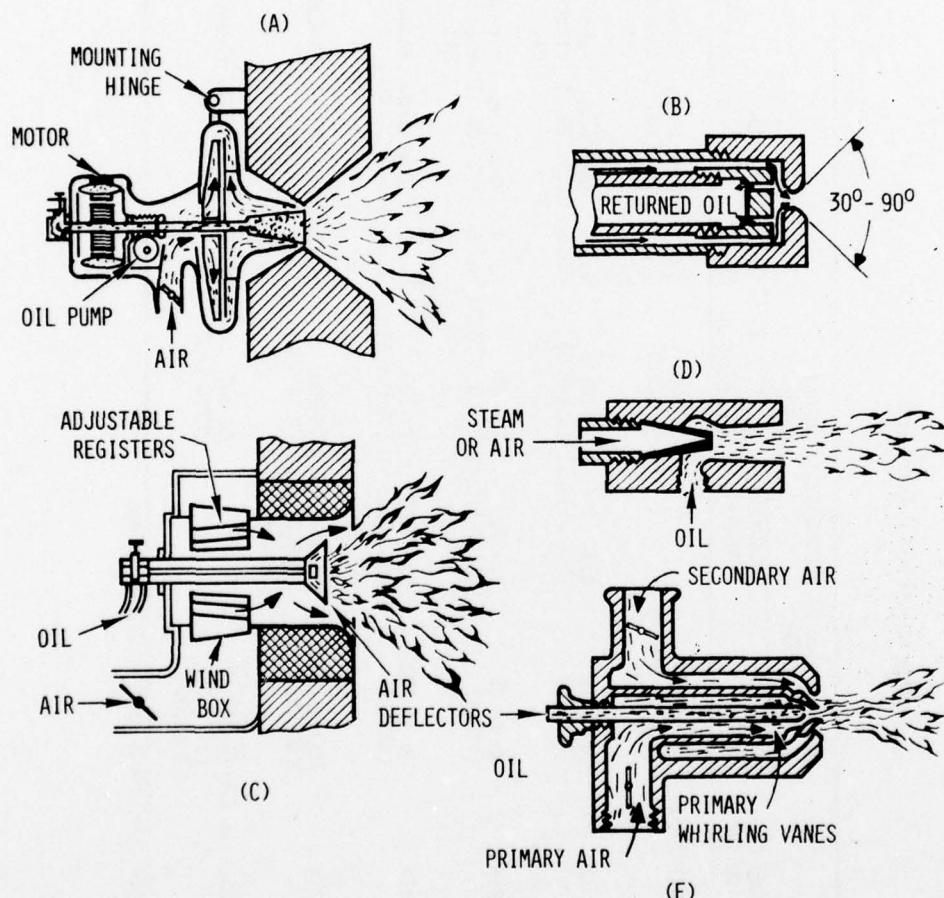


Figure 23. Principal types of oil burners: (a) horizontal rotary-cup atomizing oil burner; (b) mechanical or oil pressure atomizing burner, return flow type; (c) complete mechanical or oil-pressure atomizing burner unit; (d) high-pressure steam or air-atomizing burner, injector or venturi type; (e) low-pressure air-atomizing burner, variable pressure type. (From R. H. Perry and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. [McGraw-Hill, 1973], p 9-24. Reprinted with permission of McGraw-Hill and Hauck Mfg Co.)

Mechanical atomizers (Figures 23b and 23c) use centrifugal force to create an oil aerosol. A return-flow atomizer injects oil into a whirling chamber through tangential slots, and the resulting oil mist is ejected into the combustion chamber. Unmixed oil settles to the bottom of the whirling chamber and is recycled through the system. Required oil-injection pressures range from 600 to 1000 psi (4.1 to 6.9 MPa), depending on capacity, load range, and fuel. Low oil viscosity is essential to proper operation. Return-flow atomizers have a higher heat-release capacity than rotating-cup burners, using up to 850 gal ( $3.2\text{m}^3$ ) of oil per hour. They can burn any grade of oil if the viscosity is low enough.

Use of rotary atomizing has been limited recently due to the excessive maintenance required for moving parts in high-temperature applications.

Steam or air atomizers--the most widely used devices--mix fuel oil with air or steam, either internally or externally, and release it for combustion. The mixture expands and atomizes as it escapes. Figure 24 illustrates the various mixing principles. Steam is most popular in large boiler facilities, but compressed air may be used if steam is not available. Dry steam is preferred, since moisture may cause pulsations that will hinder ignition. Steam requirement is generally 1 percent of fuel by weight--a sizeable quantity of steam in large plants. However, substituting a compressed-air supply system for steam is rarely economically justifiable.

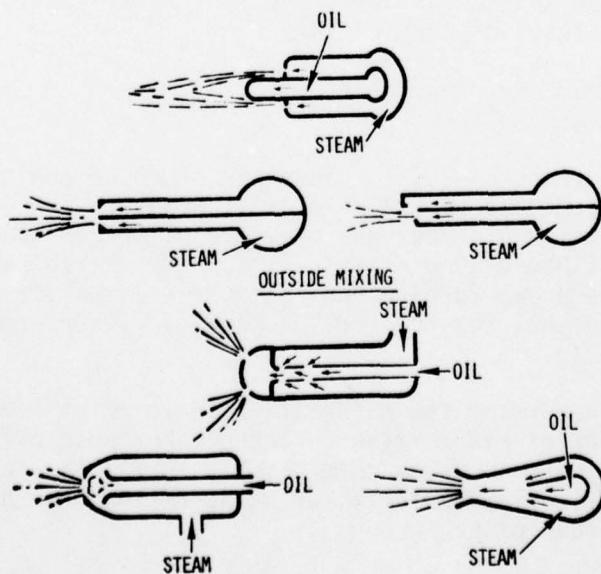


Figure 24. Principles of atomization employed in steam and air atomizing nozzles. (From M. L. Smith and K. W. Stinson, *Fuels and Combustion* [McGraw-Hill, 1952], p 229. Copyright by McGraw-Hill.)

High-pressure atomizing burners (Figure 23d), which burn up to 850 lb (385 kg) of oil per hour, use either steam or air; these have the advantages of better flame control and flow metering and good combustion efficiency for low and moderate flow rates. Air pressure must be maintained from 800 to 1000 psi (5.5 to 6.9 MPa), while steam pressures must range from 40 to 80 psi (275 to 550 kPa). Any grade of oil may be used, if the heavy oils are preheated.

Low-pressure atomizer systems (Figure 23e) are similar to high-pressure systems, except that pressures range from 0.5 to 2.0 psi (3.4 to 13.8 kPa) for steam. Common use of low-pressure atomizer systems is restricted to no. 2 oil, but no. 5 is used in some larger facilities.

#### Diesel and Turbine Fuel

Diesel engines used for stationary service respond rapidly to electrical load fluctuations and can use a wide range of fuels. As primary and auxiliary power generators, turbines have high thermal efficiency, due to the elimination of an intermediate heat exchange process.

Petroleum fuel requirements of stationary diesels and turbines must be evaluated with regard to fuel availability, costs, and effect on the performance. The storage, delivery, and handling of diesel and turbine fuels are very similar to that of fuel oils; the primary difference is preventing foreign material from entering the fuel. Uncontrolled mixing must be avoided, and fuel tanks should be used only for a specific diesel or turbine fuel.

#### *Types of Petroleum Fuel Available for Diesel and Turbine Engines*

Petroleum products used in diesel and turbine engines are produced by blending intermediate distillate oils; however, the wide variety of diesel and turbine engine designs prevents using one standard fuel. ASTM has established graded classifications for petroleum used in commercial diesel and gas turbine engines; these classifications set limiting requirements for the fuel properties within each fuel grade (Tables 20 and 21).

The broad nature of the ASTM-defined commercial fuel grades gives the user a number of alternatives. Three major possibilities are most frequently considered: using commercially available grades of fuel, securing specially blended fuels, or using residual or blends of residual and light fuel oils.

The costs of commercially available diesel and turbine fuels are directly related to quantity and quality of the distillate products

Table 20

Detailed Requirements for Diesel Fuel Oils<sup>a\*</sup>

(From "Standard Specification for Diesel Fuel Oils," 1975 Annual Book of ASTM Standards, ASTM D975-74, Part 23 [ASTM, 1975], p. 479. Reprinted by permission of the American Society for Testing and Materials, copyright.)

Grade of Diesel Fuel Oil	Flash Point, deg F (deg C)	Cloud Point, deg F (deg C)	Water and Sediment, percent	Residue on 10 Residuum, percent	Ash, weight percent	Distillation Temperature, deg F (deg C)		Viscosity at 100 F (37.8 C)	
						90 percent Point Min	Max	Kinematic <sup>c</sup> , v, cSt (x 10 <sup>6</sup> ) <sup>d</sup> /s (or SUS) Min	Cetane Number <sup>e</sup> Max
No. 1-D A volatile distillate fuel oil for engines in service requiring frequent speed and load changes.	b 100 or (37.8)	b 0.05	0.15	0.01		550 (287.8)	1.4	2.5 (34.4)	0.50 or legal
No. 2-D A distillate fuel oil for lower volatility for engines in industrial and heavy mobile service.	b 125 or (51.7)	b 0.05	0.35	0.01	540 <sup>c</sup> (282.2)	640 (338)	2.0 <sup>c</sup> (32.6)	4.3 (40.1)	0.50 or legal
No. 4-D A fuel oil for low and medium speed engines.	b 130 or (54.4)	b 0.50		0.10		5.8 (45)	26.4 (125)	2.0 30 <sup>f</sup>	
ASTM Test Method	D93 or D2500	D1796	D524	D482	D86			D445 or D2161	D129 D130 D613

<sup>a</sup> To meet special operating conditions, modifications of individual limiting requirements may be agreed upon between purchaser, seller, and manufacturer. It is unrealistic to specify low-temperature properties that will ensure satisfactory operation on a broad basis. Satisfactory operation should be achieved in most cases if the cloud point (or wax appearance point) is specified at 10 F above the tenth percentile minimum ambient temperature for the area in which the fuel will be used. The tenth percentile minimum ambient temperatures for the U.S. are shown in Appendix A2 of ASTM D975. This guidance is of a general nature; some equipment designs, use flow improver additives, fuel properties, and/or operations may allow higher or require lower cloud point fuels. Appropriate low temperature operable properties should be agreed on between the fuel supplier and purchaser for the intended use and expected ambient temperatures.

<sup>b</sup> When cloud point less than 10 F (-12.2 C) is specified, the minimum viscosity shall be 1.8 cSt and the 90 percent point shall be waived.

<sup>c</sup> In countries outside the U.S.A., other sulfur limits may apply

<sup>d</sup> Where cetane number by Method D613 is not available, ASTM Method D976, Calculated Cetane Index of Distillate Fuels may be used as an approximation.

<sup>e</sup> Where there is disagreement, Method D613 shall be the referee method.

<sup>f</sup> Low-temperature temperatures as well as engine operation at high altitudes may require use of fuels with higher cetane ratings.

AD-A063 239

CONSTRUCTION ENGINEERING RESEARCH LAB (ARMY) CHAMPAI--ETC F/6 21/4  
FUELS: STATE OF THE ART IN INDUSTRIAL UTILIZATION.(U)

NOV 78 P KONG, M LEE, S MATHAWAY

MIPR-N00025-4-1041

UNCLASSIFIED

CERL-TR-E-135

NL

2 OF 2  
AD  
A063239



END  
DATE  
FILED  
3-79  
DDC

Table 2

Detailed Requirements for Gas Turbine Fuel Oils\*  
(From "Standard Specification for Diesel Fuel Oils," 1975 Annual Book of ASTM Standards, ASTM D2880-71, Part 24 [ASTM, 1975], pp 766-767. Reprinted by permission of the American Society for Testing and Materials, copyright.)

No. 1-GT corresponds in general to Specification D396 Grade No. 1 fuel and Classification D975 Grade No. 1-d diesel fuel in physical properties. No. 2-GT corresponds in general to Specification D396 Grade No. 2 fuel and Classification D975 Grade No. 2-d diesel fuel in physical properties.

No. 3-GT and No. 4-GT viscosity range brackets Specification D396 Grades No. 4, No. 5 (heavy) and No. 6 (light). No. 5 (heavy) and No. 6 (light) viscosities are not specified.

B Viscosity values in parentheses are for information only and are not limiting.  
C Recognizing the necessity of additional requirements for certain types of gas turbines, the following tables have been prepared.

measured 12 hr after the first filter was replaced. The following results were obtained:

and the accuracy of the procedure was  $\pm 1.2\%$ . The precision of the procedure was  $\pm 1.1\%$ . The repeatability of the procedure was  $\pm 0.9\%$ . The detection limit of the procedure was  $0.001\text{ mg Hg}$ .

d except where first meeting facilities are provided.

9  
Satisfied requirements covering the addition of and the type of measures sum-containing additive  
to be used shall be specified only by the manufacturer or supplier.  
Satisfied requirements covering the addition of and the type of measures sum-containing additive  
to be used shall be specified only by the manufacturer or supplier.

**Specified agreements covering the acquisition or sale of the business between the purchaser and the seller.**

In products outside the USA, the maximum sulfur limit shall be 1.0 weight percent. Legal requirements to the contrary.

being blended. Therefore, premium fuel prices may be paid for fuel properties that are unnecessary for a specific engine. Time and geographic variations in fuel quality and availability further compound the uncertainty, and may make it impossible to secure a desired fuel.

Arrangements can often be made with the vendor to buy a specially blended diesel or turbine fuel designed to insure good engine performance. However, the fuel manufacturer or supplier must have economic incentives for preparing a specially blended fuel with narrow quality specification--either higher fuel cost or volume sales.

Because of the low cost of lower fuel grades, residual fuel oil and mixtures of light fuel oils and residual fuel oil have been considered as substitute fuels; however, their performance must be carefully examined since their high viscosity, low volatility, and combustion residue present special problems.

In comparison to ASTM-defined grades of diesel and turbine distillate fuels, residual oil and mixtures of residual and distillate fuel oils are heavier, highly viscous fuels; they have lower distillation ranges for lower volatility and contain substantially higher levels of sulphur, sediment, water, carbon residue, and ash in the form of solid particles and oil- or water-soluble lead, vanadium, calcium, sodium, and potassium salts. The increased number of particles associated with higher levels of sediment and ash require extensive filtration in the fuel distribution and injection systems to prevent turbine blade and fuel injector wear. The high sulfur levels, carbon residues, and higher water content require more frequent diesel lubricating oil changes, special corrosion-resistant turbine blades, freshwater washing, and magnesium additions to inhibit deposits and corrosion.

The high-viscosity fuel would cause fuel injection and flow problems and require auxiliary heating equipment for storage, distribution, and injection. The fuel's low volatility causes cold-starting problems which would require light, highly volatile fuels for starting and stopping; this would create a need for separate storage and distribution systems for light oils and the heavier substitute fuels. In addition, residual-distillate fuel oil mixtures must remain homogeneous, which requires mixing.

To accurately evaluate this alternative, the benefits of greater availability and lower costs of substitute low-quality fuels would have to be weighed against the cost of modifying the diesel and turbine engine, or the fuel system, or both.

#### *Properties of Diesel and Turbine Fuels*

The advanced technology of turbine and diesel engines has identified certain petroleum properties which induce operational and maintenance

problems. In diesel engines, four important fuel characteristics must be considered: sulfur content, ignition quality, volatility, and the fuel's smoke-producing character.

The sulfur content of petroleum increases wear on pistons, rings, and cylinder liners. Increased sulfur levels require frequent change of lubricating oil. These problems can best be minimized by using low-sulfur fuels.

The ignition quality of petroleum is determined by the ASTM Cetane Number Index (see ASTM D613), a rating system similar to the octane number for gasoline. The engine noise associated with knock and engine roughness declines as the cetane number increases.

The volatility of petroleum, as measured by its distillation point, is primarily responsible for ease of cold-engine starts. A cold engine requires a highly volatile, easily ignited fuel to start. Also, since a fuel's cetane number is related to its volatility, higher cetane-numbered fuels contribute to ease of starts.

Diesel engine smoke can be divided into two classes: a black smoke caused by soot formation and a white smoke associated with a cold start. Black smoke formation is more frequent in fuels having a high cetane number. This type of fuel has low thermal stability since it burns as a diffusion flame with little premixing with air. However, premixed flames of fuels having lower cetane numbers can cause black smoke formations if they are run rich (air-deficient). Because of the relation between cetane number and distillation point, the volatility of petroleum may be related to black smoke formation. However, a definite conclusion has not been validated by research.

The practical control of diesel fuel ignition quality, ease of starting, and smoke formation is blending distillate products to achieve a satisfactory quality, followed by adding additives to control remaining problems. However, antismoke, antiknock, and cetane-number-improving additives have a metallic base which can cause deposits in the engine; also, large amounts must be added in cold weather, thus increasing fuel costs substantially.

Petroleum fuels for turbine engines have six major characteristics: smoke formation, abrasive particle content, carbon residue, kinematic viscosity, ash and sediment, and formation of particulate ice or wax crystals.

The susceptibility of some gas turbine engines to smoke formation is related to fuel volatility, as measured by distillation point. Using highly volatile petroleum products will control turbine smoke formation.

Since fuels are characteristically injected into combustion chambers at high velocities, wear of fuel injection systems increases as the water and abrasive solid particles associated with the ash and sediment in petroleum increase.

Carbon residue from the coking of oil at high temperatures often causes injector (nozzle) tip fouling.

Engine power loss is related to the kinematic viscosity of the petroleum fuel. Low-viscosity fuels promote injection pump and leakage around worn parts, causing the engine to lose power. High-viscosity fuels can cause trouble because of the high pressures in the injector nozzle, filter capability problems, and fuel pumping problems.

Fuel starvation occurs when the fuel filter becomes plugged with captured particles due to high ash and sediment content; subsequent high-pressure drop across the filter inhibits fuel flow. This condition is also dependent on the ambient air temperature, the fuel's water content, and the fuel's pour point and cloud point.\* High ash and sediment content also necessitates more frequent filter changes.

Low-temperature operational problems are prevalent in regions where the ambient air temperature falls below freezing and the fuel's pour point and cloud point temperatures. Ice crystals form when water in the fuel freezes, and particulate wax crystals form at the cloud point temperature. These crystals are large enough and concentrated enough to plug the filter, causing fuel starvation and shortening the filter life.

Injector wear, injector deposits, and fuel flow problems can be controlled by several methods. First, contaminant levels in blends must be limited properly. Additives can depress the freezing point of the water and lower the pour point/cloud point. Kerosene dilution reduces the wax crystal size and increases the permeability of the wax filter cake. Regionally or seasonally blended petroleum can meet the demands of a given area or season. Maintaining low contaminant levels through clean transportation, storage, and distribution of diesel fuels will minimize operational problems.

The following are general rules for maintaining a clean operation.

1. Maintain a closed system of operation to minimize seepage of contaminants into the system and to eliminate fuel leakage.
2. Maintain the storage stability of the petroleum.

\*Cloud point is the temperature at which the fuel becomes cloudy due to the formation of wax crystals.

3. Allow storage tanks to settle prior to fuel removal. Remove fuel from the top of the tank. Periodically remove settled sludge to minimize particle carryover.

4. Filter the fuel before pumping to protect the fuel pump.

5. All petroleum products are not compatible; therefore, never contaminate a diesel or turbine fuel with another type of fuel, because it can cause emulsion difficulty, a safety hazard, or a vapor lock.

Using regionally or seasonally blended petroleum products gives rise to problems of insuring cold-temperature operation of diesel and turbine engines. Petroleum blending may be based on an average temperature or a maximum recorded temperature; however, blends should also be based on the frequency or recurrence of climatic conditions and on established temperature trends.

#### *Stability*

The ASTM Accelerated Stability Test (ASTM D2274) measures a petroleum product's resistance to decomposition from oxidation, which produces a sediment of insoluble residues and gum. Like most chemical reactions, the oxidation of petroleum caused by air or water in the fuel is accelerated by prolonged periods of heating and mixing, such as those occurring during refining. Catalytically cracked petroleum is less stable than thermally cracked petroleum or even the straight-run distillates. Instability causes plugged filters, injection system wear, and lacquer-like deposits, all of which are highly undesirable effects.

Using additives and correctly choosing refining techniques will control petroleum stability. Antioxidant additives minimize petroleum decomposition and the production of insoluble residue and gums; dispersants and metal-deactivating fuel additives scatter the smaller, slower-settling particles, which oxidize throughout the fuel.

Safe handling and storage of a petroleum product is directly related to the fuel's flash point. Fire and insurance regulations establish allowable temperature levels for blending.

#### Summary

To minimize difficulties of diesel and turbine engine fuels, the following general principles should be observed.

1. Minimize the fuel's sulfur, ash, water, sediment, and carbon residue during the blending process.

2. Increase the flash point and storage stability during blending and the use of stability-improving additives.

3. Minimize engine corrosion, air pollution, and fuel filtering problems by correctly choosing refining techniques and by using additives.

Diesel and turbine engines are designed to operate within certain fuel-quality ranges, because their performance is dependent on individual engine parameters (design, speed, size, load, cycle, temperature, etc.). The consumer is responsible for individually evaluating readily available fuels and their costs, engine performance, and the cost of modifying the engine or fuel to upgrade engine performance.

#### 4 USE OF REFUSE AS A FUEL\*

During the past few years, there has been substantial advancement in the art of economically recovering saleable materials and useful energy from wastes generated at military installations. The rising costs of collecting and hauling waste materials and the decreasing availability of land area for landfill have also favored resource recovery. A few years ago, resource recovery systems were economically viable only in large municipalities generating solid waste at a rate greater than 500 tons/day (450 Mg/day). Small-scale systems can now be equally attractive economically.<sup>20</sup>

Nearly all proven systems for converting refuse to energy (CRE systems) are based on incineration. An advantageous byproduct of waste incineration is the generation of useful heat, which can supplement steam and hot water supplies in CRE systems. Unlike fuel oil or coal, refuse-derived fuel (RDF) can be a low-cost supply of low-sulfur fuel.

Energy-recovery systems may be packaged ("off-shelf," highway-shippable) or field-erected (on-site assembly of components). The type of system recommended for a particular site depends mainly on the quantity and heat content of wastes available and the magnitude of steam demand through a typical day. As a very general rule, sites generating conventional mixed solid waste at a daily rate between 25 and 35 tons (23 to 32 Mg) may find implementing a relatively inexpensive package scale system economically attractive depending on the extent of waste preprocessing (e.g., size reduction by shredding) required and the ease of moving steam to an existing distribution system or user. Field-erected systems can become economical at daily conventional mixed solid waste generation rates ranging from 80 to 100 tons (73 to 91 Mg). The type of system applicable for installations generating between 35 and 80 tons/day (32 to 73 Mg/day) is usually determined in light of site-specific criteria. Because of the many factors involved in using solid waste as fuel (such as matching steam loads, tailoring a combustion system to waste of a

\*The main portion of materials presented in this section are condensed from parts of (1) S. Hathaway and J. Woodyard, *Technical Evaluation Study: Energy Recovery Utilization of Waste at Puget Sound Naval Shipyard, Bremerton, Washington*, Technical Report E-89 (CERL, March 1976) and (2) S. Hathaway and R. Dealy, *Technology Evaluation of Army-Scale Waste-to-Energy Systems*, Appendix A, Interim Report E-110) ADAD42578 (CERL, July 1977).

<sup>20</sup>S. A. Hathaway and H. G. Rigo, *Technical Evaluation Study: Energy-Recovery Solid Waste Incineration at Naval Station Mayport, Florida*, Technical Report E-51 (CERL, February 1975).

particular nature, and geographic variations in pollution abatement laws), an engineering study is usually required to assess the economics of energy recovery at a particular location.

#### Package CRE Systems

The largest package systems have waste throughput capacities of about 1.5 tons/hour (1.4 Mg/hour). The furnace configurations available include:

1. Rotary Kiln (inclined, slowly rotating, continuously fed cylindrical furnace)
2. Starved Air (stationary bed, cylindrical batch fed furnace)
3. Basket Grate (inclined, slowly rotating, continuously fed, cone-shaped furnace)
4. Auger Combustor (continuously fed, cylindrical furnace in which burning waste is moved the furnace length by an air-cooled auger).

Of these furnace configurations, only the starved-air furnace has been proven.

The process flow for all package CRE systems is fundamentally the same. Mixed solid waste is collected and delivered to a CRE facility where it is weighed and processes. The main processing operations are usually size reduction by shredding, temporary storage, burning, and use of heated off-gases to produce saturated steam in a heat exchanger located after the furnace. A surge area is provided in the processing line. Appurtenances include water treatment, ash removal, and pollution control equipment.

Solid waste deliveries are weighed at the CRE facility's entrance by a standard platform scale. The weigh station may be manned or automatic.

There are various means of initially handling solid wastes delivered to the CRE facility. For larger waste streams, a pit-and-crane operation may be desirable. Waste is dumped directly into the pit, which is usually designed to accommodate surge quantities. A ceiling-mounted crane moves material from the pit to further processing. Oversized bulky wastes are removed, and incombustible bulkies are separated for disposal or recycling. Combustible materials either too large or of too great a structural strength to be handled with mixed solid waste in subsequent processing stages may be diverted to an auxiliary heavy-duty shredder for breakdown. A system using a tipping floor and front-end loader is an alternative to the pit-and-crane operation. Delivered solid waste is dumped on the floor and moved by the loader either to a temporary storage area or directly to processing. Bulkies are handled as described above.

From the delivery point, solid waste may be conveyed to temporary storage, to further processing, or directly to the incinerator. Although most currently marketed package incinerators are designed to accommodate unprocessed solid waste, it is sometimes preferable to shred the material in CRE applications. Shredding loosens and reduces the waste to a smaller and more easily handleable particle size range, increases the surface/volume ratio and hence the material's combustibility, and by mixing, makes the charge more homogeneous than unprocessed solid waste. Shredding increases the ease and efficiency of thermal processing and gives stability to heat exchanger performance. A wide variety of size reduction hardware is currently available, and selection of an appropriate unit depends heavily on the nature and quantity of the solid waste. In general, heavy-duty, vertical-feed, reversible-drive hammermills with replaceable hammer tips are adequate for the typical military base solid waste stream. Complete redundancy at this processing stage is desirable, since shredders are high-maintenance items, and continuous, reliable processing of solid waste is necessary.

It is usually preferable to keep solid waste moving through a CRE system. This strategy avoids many difficult handling problems associated with storage of moist, putrescible materials. Often, however, temporary (up to 3 days) storage is necessary, which can be accomplished in the receiving pit. Shredded solid waste can also be stored in agitated bins, but this approach usually means higher capital investment and operating costs. If a tipping floor is used, it should be adequately sized to accommodate storage and surge requirements.

Shredded solid waste is fed into the package incinerator as required to operate the CRE system at nominal capacity. Incinerator feeding is either continuous, semicontinuous, or batch, depending on the unit's design. Batch-fed incinerators are usually unfavorable in CRE applications, because they make it difficult to maintain continuity in steam production and solid waste disposal.

The final stage of the incineration process is usually afterburning. In CRE applications, afterburners should be temperature-activated and should limit the temperature range of combustion products entering the heat exchanger.

Three types of heat exchangers can be used. Steam is generated in watertube or firetube package boilers or, as in the case of the recently developed augered-bed system, in a coiled heat exchanger between the furnace and air pollution control hardware. Firetube boilers have been used in series with both rotary-kiln and starved-air incinerators with only minor difficulty. The firetube boiler should be selected for once-through design, since entrained fly ash will be deposited if there are multiple turns in the gas pass.

The load-carrying and response characteristics of watertube boilers are superior to those of firetube units. It is desirable to precede a water-tube boiler with a waterwall quench section where the bulk gas temperature is reduced to below 1900°F (1038°C). Above this temperature, entrained particles impinging on tubes tend to adhere, making cleaning difficult, promoting fireside metal wastage, and upsetting the system's design heat balance.

Whichever type of boiler is selected, it is necessary to install hoppers beneath the tube passes and to furnish sootblowers. The design should also provide for automatic ash handling. Most available package incinerators include at least semicontinuous ash and residue removal. To maintain consistent steam output when incinerators are down, there should be burners and kindred appurtenances for direct firing of the heat exchanger with clean fuel. When heat exchangers are clean-fuel-fired, gases may be passed through bypass breeching around the air pollution control equipment.

Proven, available air pollution control equipment is the next step in the package CRE system. Since mixed solid waste can contain up to 25 percent ash, high mass emission rates may be expected. Wet or dry pollution abatement systems can be used; however, wet systems consume large amounts of power and cause a water treatment problem. Venturi scrubbers and high-draft water spray cyclones have successfully reduced emissions from CRE systems, but their use might mean higher capital and annual costs from water treatment requirements. If a wet ash removal system is used, it is often convenient to use scrubber wastewater for quenching. Use of a scrubber usually requires a demister to inhibit mechanical deposition of droplets on the induced draft (ID) fan. Baghouses and electrostatic precipitators are the chief alternative dry collection systems. To reduce the possibility of filter fabric damage, a cyclone separator is used before the baghouse. High-temperature corrosion and abrasion-resistant media such as fluoro-carbon are recommended. Utility operating costs of both systems are generally comparable. A baghouse normally has a large ID fan horsepower requirement, since pressure drops across the unit can be great. Precipitators are large electricity consumers. A precipitator-based design places a low-efficiency cyclone ahead of the ash storage bin to remove any hot cinders which might cause an explosion. Material collected in the cyclone for both the fabric filter and electrostatic precipitator systems should be quenched before being admitted to the ash bin. A precipitator system may require preconditioning of the flue gas with SO<sub>3</sub>. Since solid waste contains very little sulfur, the particulate material's resistivity at the collection electrode may adversely affect the unit's collection efficiency.

Preparing and using solid waste as a fuel can create numerous environmental hazards. Air hoods are required for shredders whose off gases contain up to 0.05 percent of the feed as entrained dust. High chloride emissions from the combustion process are possible, because

the heavier fractions of solid waste may contain substantial quantities of polyvinylchlorides. If large quantities of plated metals are present, high concentrations of zinc, tin, cadmium, lead, and antimony will be emitted as a submicron heavy aerosol formed by reducing and evaporating these metals in the fuel bed and oxidizing the vapor as it passes through the flame front. The metals will either coalesce as a heavy metal aerosol or plate out on the ash matrix. Because of varying resistivities, some trace metals may pass through an electrostatic precipitator. By taking combustion air from solid waste delivery and storage areas, odors can be controlled effectively. Noise from shredding operations can be reduced either by properly designing the unit housing or by installing acoustic partitions. For safety, shredders should be surrounded by blast partitions, with low-resistance blast panels installed on the ceiling.

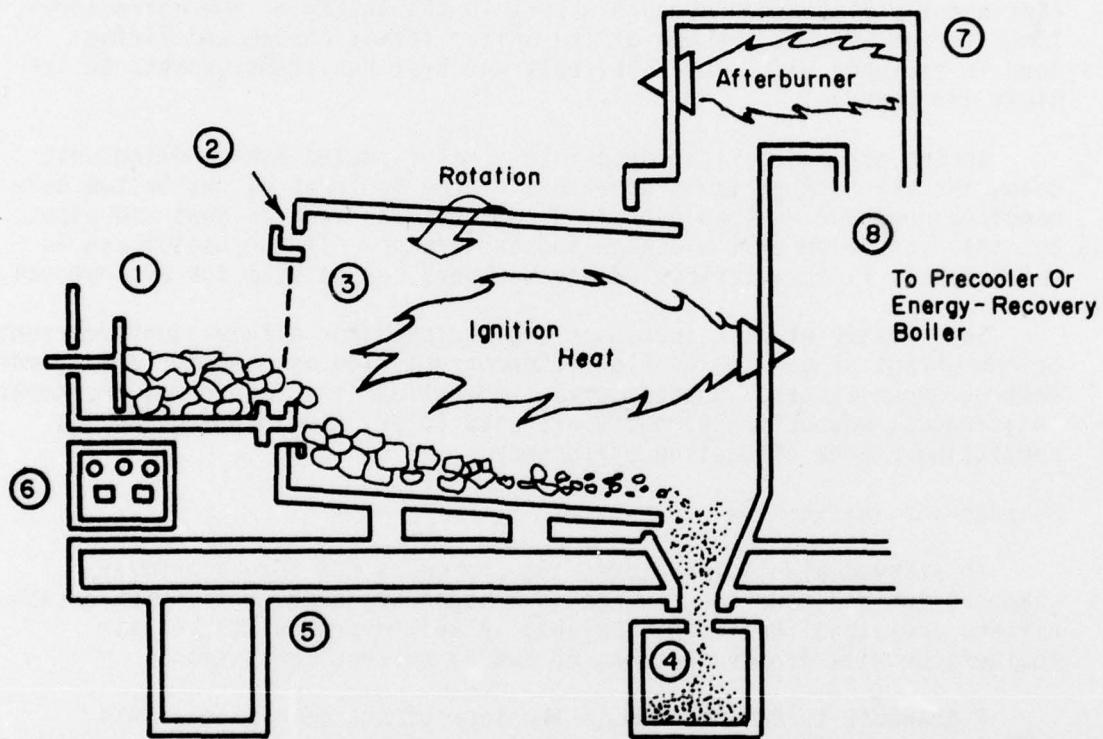
Depending on the nature and quantity of solid waste being processed, profitable materials recovery stages may be included in the CRE system. A variety of proven hardware is available for magnetics recovery, and can be placed either before or after the shredding stage. If economical, an aluminum recovery system can follow magnetics recovery. Separation of glass and cullet is more difficult, usually requiring additional shredding and agitated screening and wet recovery stages such as flotation. Such recovery systems require high investment and operating costs. It has been demonstrated frequently that the most economical way to isolate salvageable materials from other wastes is to conscientiously practice source segregation.

#### *Rotary-Kiln Incinerator*

The primary combustion chamber of a rotary-kiln incinerator is a slightly inclined, refractory-lined cylinder (Figure 25).

During combustion, the kiln rotates around its longitudinal axis of symmetry, continually mixing the charge mechanically as it is being conveyed to the discharge end. The constant motion effectively breaks cake layers on the charge's surface, continually exposing fresh surfaces and increasing combustion efficiency. In a well-operated unit, there is approximately 92 percent combustion. The combustible material dries quickly, ignites, and burns thoroughly. Combustion air is preheated by reflected heat from within the kiln. The ignition burner is located at the discharge end of the kiln and may be fueled with light or heavy oil, gas, or flammable liquid waste material. Temperatures sufficient to sustain ignition are normally maintained by the burning charge after start-up. Additional fuel can be supplied to the kiln when wastes having a heating value too low to support self-combustion are being burned. This auxiliary fuel may be mixed with the charge or burned in either an auxiliary burner or the ignition burner.

In CRE systems using the rotary-kiln unit, the package boiler is installed after the afterburner. The energy-recovery efficiency of



- 1 Coarse RDF Auto-Feed (Hopper, Pneumatic Feed, Slide Gates)
- 2 Forced Air
- 3 Refractory-Lined Rotating Cylinder (Primary Chamber)
- 4 Ash Hopper (Incombustibles)
- 5 Support Frame And Piers
- 6 Control
- 7 Secondary Chamber
- 8 To Appurtenances

Figure 25. Rotary-kiln incinerator.

these systems can range between 60 and 75 percent, including boiler and breeching losses.

The rotary kiln can burn mixed solid waste as received. Oversized bulky wastes are usually shredded to insure complete combustion within reasonable detention times. Feeders on commercially available units are designed to accommodate feed variability. Sludges and similar wastes are usually mixed with a variable supply of solid waste before charging.

A ram feeder can be used to charge the primary chamber. Ash is continuously discharged through a port in the bottom of the refractory-lined firing hood at the end of the unit. The discharge end firing hood is equipped with labyrinth seals and heat-resistant gaskets to inhibit air leakage.

Bottom ash and residue drop into a water-sealed ash-handling unit below the kiln. A grate is sometimes placed in front of the bottom ash-handling hardware to trap oversized combustibles such as cans and pipes, but this can cause exit blockage and ash backup. If the bottom ash is sufficiently fine, water-cooled screw augers can be used for ash removal.

Some rotary-kiln incinerators are equipped for either countercurrent or concurrent or gas/charge flow. Concurrent flow is used for drier, more heterogeneous wastes. Countercurrent operation is suitable for incinerating sludges; combustion products are used to dry the incoming charge, permitting higher combustion efficiency.

#### *Starved-Air Incinerator*

In starved-air incinerators, the charge is fed into a primary chamber, ignited, and then burned in a secondary chamber to which excess air and additional heat are supplied. A well-operated starved-air incinerator will achieve between 80 and 93 percent combustion.

A drawback to this system is the lack of charge mixing. This deficiency normally prevents the material from being completely burned and often causes furnace pulsations. As a result, energy-recovery efficiencies average only 55 percent, but can be as high as 75 percent. Temperature is controlled by adding air and auxiliary fuel to the afterburner and sometimes modulating the air supply. However, in an improperly operated unit, the carbon content of ash emitted from the furnace is often high.

Several vendors have starved-air units with semi-automatic feeders and semicontinuous ash-removal systems. Currently, however, fully automatic ash removal is not proven technology. Because of high temperature slagging in the primary chamber, the unit has a comparatively large fraction of downtime, with corresponding high operating and maintenance costs. Most available units require moderate quantities of auxiliary fuel, although recently developed combustion controls which

automatically modulate excess air in the afterburner have reduced clean fuel requirements. Underfire air has been modulated in attempts to achieve constant quality of off gases passing to the afterburner.

There are two basic starved-air incinerator configurations. The first is comprised of two "piggy-back" combustion chambers (Figure 26), in which refuse is charged to the primary (lower) chamber through an air curtain. When the temperature in the primary chamber reaches approximately 600°F (316°C), a stream of air passes over the fire. Incombustible materials precipitate to the grateless bottom of the chamber, and the remaining solids, gases, and odors rise to the upper or secondary chamber where excess air is added. Thorough mixing is maintained by baffling excess air as it is added.

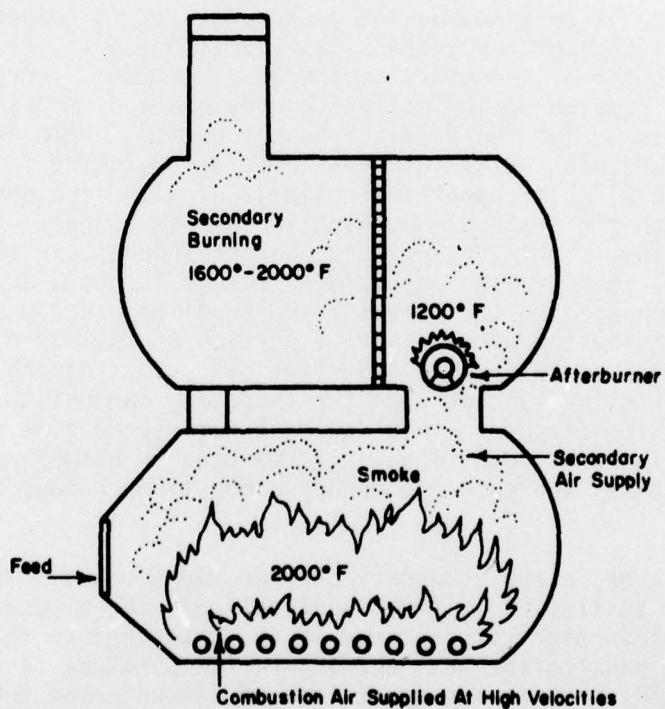


Figure 26. Starved-air incinerator (first major configuration).

The second type of starved-air incinerator uses a substantially smaller secondary combustion chamber. These units process the charge similarly to the units discussed previously. The charge is partially pyrolyzed in the primary chamber, and the products are then passed through an afterburner located above the primary chamber. The afterburner is clean-fuel-fired, and effects complete combustion of the pyrolysis products in an excess air environment.

### *Basket-Grate Incinerator*

The basket-grate incinerator (Figure 27) is capable of firing mixed solid waste as delivered. The primary chamber is an inclined ( $30^\circ$ ) truncated cone-shaped grate supported by an externally driven frame.

The basket grate is semicontinuously charged with material to approximately 20 percent of its total volume and rotated slowly around the cone centerline. The inclination and rotation cause heavier materials to fall toward the larger (outer) basket diameter and the smaller materials to fall toward the smaller (inner) diameter. The three-dimensional self-ranking effect of the virtually endless grate maximizes mechanical and thermal destruction of the charge.

The charge is retained on the grate until it is reduced to a size which can pass through the grate slots (about 0.125 in. [3.18 mm]) into an ash hopper or secondary incineration chamber. Large incombustibles can be removed periodically from the grate by means of a grated plate which can be lowered from the basket bottom. Some problems have been experienced with bulky incombustibles accumulating in the cone which reduce available combustion volume, and with fine combustibles sifting through the grate and burning in the ash hopper. Negative relative pressure within the primary chamber induces air through the ash collector, so that ash and residue leakage is not a problem. An external fan mounted on the swivel frame supplies primary air to the furnace. Distribution pipes divert a portion of the air directly beneath the firebed to provide underfire air. Part of the combustion air is tangentially injected into the secondary combustion chamber located above the firebed. This causes a turbulence zone which effects efficient mixing and combustion. Afterburning is normally self-sustaining. Gases leave the secondary combustion chamber through the crown.

Temperatures in the secondary chamber range between 1500°F and 2100°F (815°C to 1150°C). In CRE applications, the afterburner is fired to maintain high temperatures in the gases before they leave the exit port and pass to the heat exchanger. Temperature is controlled by automatically varying the quantities of air entering the primary and secondary chambers in an inversely proportional manner. In normal operation, high off-gas temperatures can be maintained at approximately 70 percent excess air. Auxiliary fuel is usually required only during startup, which can be completed in 15 min. After the unit has been brought on-line and stabilized, no additional fuel is necessary.

Available units achieve 90 to 96 percent reduction of combustible materials for IIA Type 1<sup>21</sup> waste. The quantity of incombustible

<sup>21</sup>Incinerator Standards (Incinerator Institute of America, 1970), p 3-A.

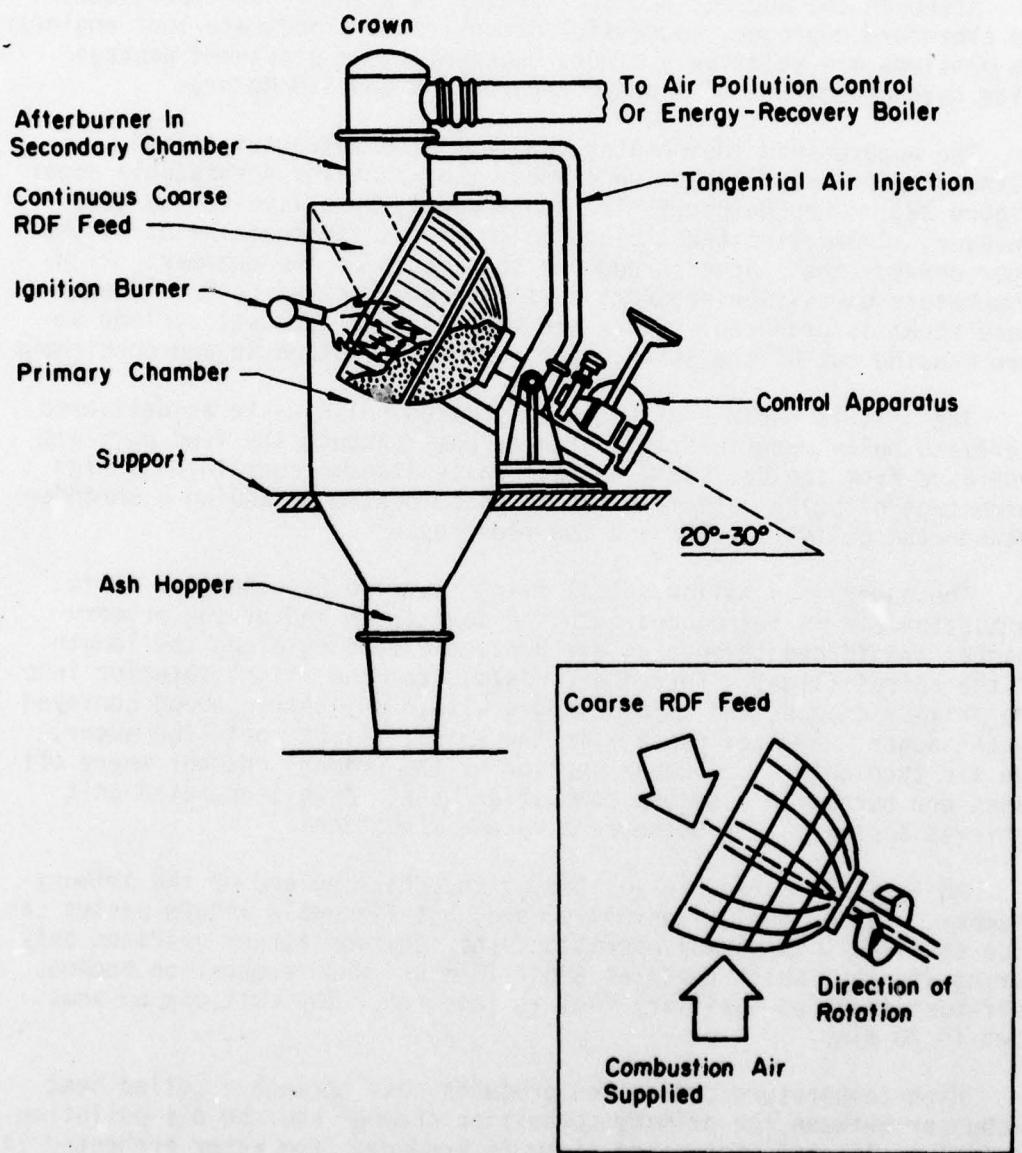


Figure 27. Basket-grate incinerator.

residue remaining in the ash rarely exceeds 5 percent. Because the unit is designed to maximize combustion, energy-recovery efficiencies average 68 percent.

#### *Augered-Bed Incinerator*

Although the augered-bed incinerator is a very recent development and therefore unproven, successful demonstrations indicate that engineering problems are relatively minor. Currently, manufactured package units have capacities of 1 and 5 tons/hr (.9 and 4.5 Mg/hr).

The augered-bed incinerator consists of a refractory-lined cylindrical primary combustion chamber that contains a rotatable auger (Figure 28). The chamber is fed continuously by a live-bottom feed conveyor. Combustion takes place in an excess air environment as the auger conveys the charge throughout the length of the chamber. High-temperature combustion products pass through a coiled heat exchanger where steam is produced. Gases are then cleaned in a wet cyclone before passing out of the stack. Ash removal is automatic and continuous.

The unit is capable of processing mixed solid waste as delivered. Oversized bulky materials too large to pass through the feed port are separated from the delivered waste. Waste streams containing a high percentage of bulky materials can be accommodated by adding a shredder between the delivery point and the feed hopper.

The auger is a hollow spiral flight carried by a tubular shaft. Combustion air is introduced into the downstream end of the primary chamber and forced through an air passage extending along the length of the spiral flight. Forced air passes from the flight interior into the primary chamber and is discharged within the charge being conveyed by the auger. A water passage in the spiral flight cools the auger. The air then enters the upper portion of the primary chamber where off gases are burned in a second combustion zone. A well-operated unit achieves approximately 95 percent volume reduction.

An ignition burner is located at the charging end of the primary chamber. Gas or fuel is normally used, but flammable liquid wastes can also be fired. In normal operation, the ignition burner operates only during startup, which requires about 15 min. When combustion becomes self-sustained, no auxiliary fuel is required. The unit can be shut down in 20 min.

High-temperature combustion products pass through a coiled heat exchanger between the primary combustion chamber and the air pollution control equipment. Saturated steam is produced from water preheated in the spiral flight.

The computed energy-recovery efficiency of this system is 65 percent; operating experience is required to determine whether this is an accurate design parameter.

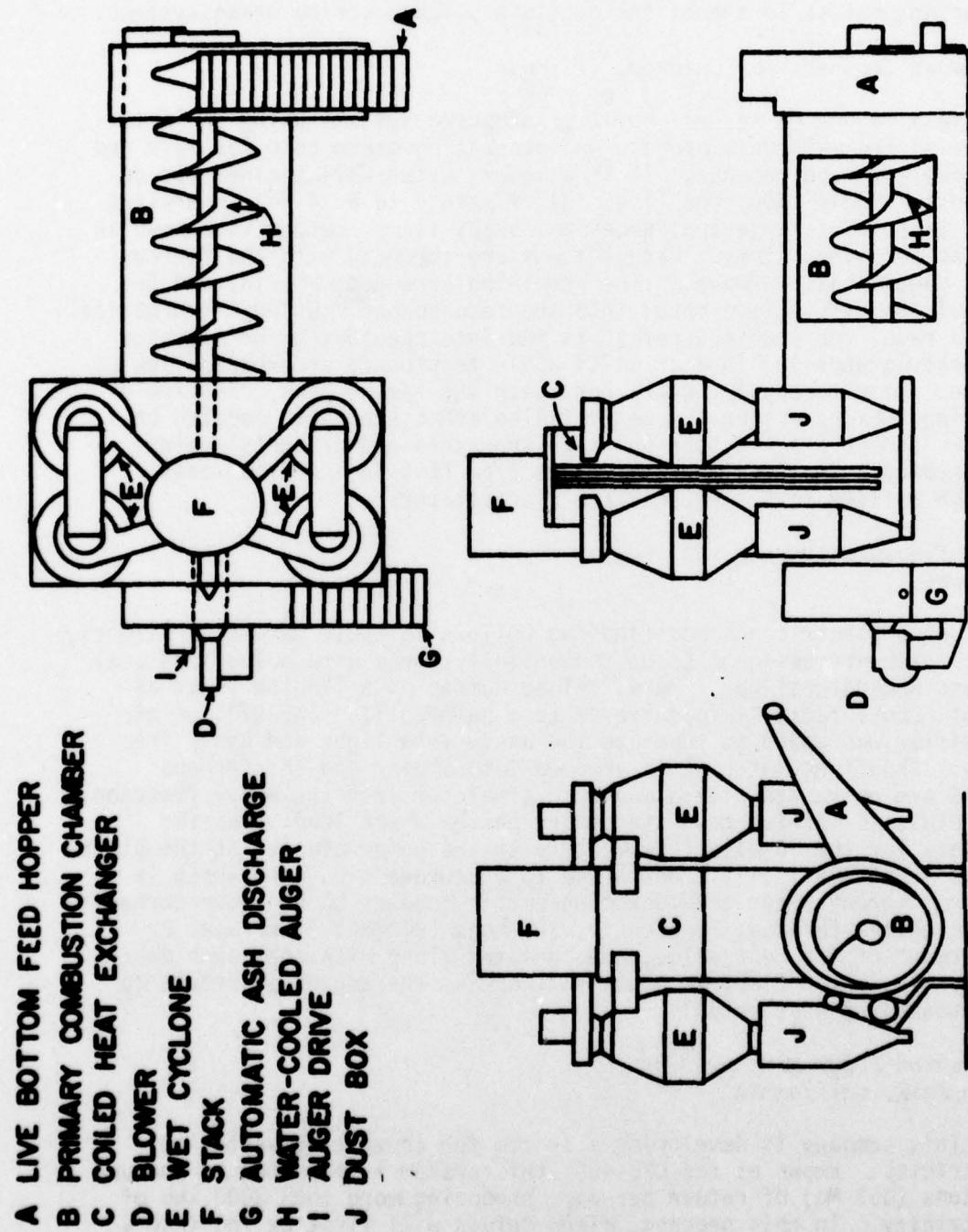


Figure 28. Augered-bed incinerator.

### Field-Erected Systems

Currently, several plants in the U.S. and Europe are economically converting refuse to steam; the sections below describe these systems.

#### *Northwest Incinerator, Chicago, Illinois*

This is one of several built or proposed systems using an incinerator as the main unit process and generating steam both for sale and for in-plant requirements. It is a modern water-wall incinerator designed to handle 1600 tons (1.45 Tg) of refuse in a 24-hour operating day. Except for large appliances and bulky items, refuse is burned in the "as-received" state. Larger items are shredded with the ferrous metal magnetically removed. The remaining shredded material and the rest of the refuse is dropped into the feed hopper. Using a hydraulically fed ramp, the combined refuse is fed into the four-burner furnace on stoker grates inclined at a 26° angle to produce a downward flow of refuse. Simultaneously, grate bars push the refuse back, creating a tumbling, mixing action. A water-filled ash discharger, located below the stoker grates, both quenches the ashes and protects against gas seepage. The resultant hot gases from this incineration pass through boilers into electrostatic precipitators.

#### *Union Electric Company, St. Louis, Missouri*

Union Electric has modified two boilers in their Meramec, Missouri, plant which are designed to be tangentially fired with pulverized coal burners and natural gas. Here, refuse dumped on a tipping floor at the St. Louis facility is conveyed to a hammermill. In 1973, an air classifier was added to separate the waste into light and heavy fractions. The light material is dropped into a bin, and the ferrous metals are extracted with a magnetic separator from the heavy fraction. Bin refuse is carried to a stationary packer which loads transfer trailers for the 18-mile (29-km) trip to the power plant. At the plant, refuse is pneumatically transferred to a storage bin, from which it is taken through four air-locked pneumatic feeders to the four corners of the boiler furnace. Presently, 300 tons (272 Mg) of refuse, or 10 percent of the heat value, are consumed along with coal each day. Eventually, Union Electric hopes to increase the amount of refuse to 20 percent (by heat value).

#### *Combustion Power Company, Inc., Menlo Park, California*

This company is developing a system for converting wastes to electricity. Known as the CPU-400, this system is expected to consume 400 tons (363 Mg) of refuse per day, producing more than 8000 kWh of electricity. In this process, mixed refuse will first be fed into a shredder, then taken to an air classifier, where metals and glass will

be separated and removed. The remaining material will be transported to a storage container from which it will be metered by an air-lock feeder into a fluid-bed combustor. There, the material will be burned under controlled high pressure to produce hot gases. These gases will later pass through cleaning devices and into the gas turbine driving the generator. Combustion Power estimates operating costs to be about \$2.50 per ton (\$2.76 per Mg) of refuse. A 1/5-scale pilot plant is presently operating in Menlo Park, California, as part of the final system development stages.

*Combustion Power Company, Inc.  
Munich North, Block I*

This plant consists of two identical Benson-type units. These are the oldest of the units under consideration and are characterized by twin-chamber furnaces; i.e., the refuse and coal-furnace chambers are separate but share a common tube-wall. The combustion gases are combined at the top of the furnace chambers and then are passed through a common superheater and economizer. All of these elements comprise one furnace setting or unit. Each unit includes a Martin (backward reciprocating) grate for municipal refuse combustion and a suspension-fired furnace chamber for the combustion of pulverized coal. Steam conditions for each Block I unit are 220,000 lb/hr (100 Mg/hr) of 2600 psig (17.9 MPa gage) at 1004°F (540°C) while firing 660 tons per day (599 Mg/day) refuse plus auxiliary coal. Maximum continuous load is 220,500 lb/hr (100 Mg/hr) of super-heated steam at 2,650 psig (18.3 MPa gage) and 1004°F (540°C). The reheat steam flow at this load is 198,000 lb/hr (89.8 Mg/hr) at a pressure of 1180 psig (8.1 MPa gage) and 1004°F (540°C). Ferrous metals are removed from the combustion water-quenched residue by magnetic equipment.

*Combustion Power Company, Inc.  
Munich North, Block II*

This unit is the latest design (1966) under consideration. It was evolved from the Block I units, but with one important design change. The Block II unit is a single-chamber furnace, with pulverized-coal combustion occurring directly above the refuse grate. Steam quality is identical to that of the Block I units; however, steam production, at 800,000 lb/hr (363 Mg/hr) is considerably higher.

All the electrostatic precipitators of the Munich North plants are of the Lurgi (Frankfurt) design and are horizontal-flow, steel-shell precipitators having pyramidal hoppers.

The differences between the Munich North plants can be seen from the following summary.

	<u>Block I</u>	<u>Block II</u>
No. of Turbines	1	1
No. of Steam Generators	2	1
Refuse Heat Input, percent of lower heating value	40	20
Refuse Rate, tons per day (Mg/day)	660 (599)	1060 (962)

#### *Dusseldorf*

This company consists of four essentially identical boilers, arranged in pairs. The Dusseldorf furnace is primarily for firing refuse, although there are auxiliary oil guns that can be used for startup and when the heating value of refuse is low. The refuse is fired on a roller grate; as at Stuttgart, only bulky refuse is shredded. The combustion air can be directed over a steam air-preheater and a feedwater/air-preheater if heating is desired. Three electrostatic precipitators treat the combined flue gases of four units. There is also provision for recirculating waste gas.

Each system generator is designed to deliver from 25,500 to 35,200 lb/hr (11.6 to 16 Mg/hr) of steam at 1,280 psig (8.8 MPa gage) and 932°F (500°C). The roller grate is designed to burn 22,050 lb/hr (10 Mg/hr) of refuse with an exit gas temperature of 410°F (210°C).

#### *Stuttgart*

The Stuttgart plant consists of two nearly identical units. Both units have one oil-furnace and one refuse-furnace; in each, the gases combine before entering the convection section. As with the other German units considered, there is provision for recirculation of the flue gases to cool the residue. The units have steam/air and waste gas/air (panel design) air heaters. The steam generators are designed to deliver 204,600 lb/hr (92.8 Mg/hr) steam at 925 psig (6.4 MPa gage) and 977°F (525°C) for normal operation with either oil firing or combined firing. The maximum continuous power level is 275,600 lb/hr (125 Mg/hr) steam at the same conditions. The boilers were designed to handle 40,920 lb/hr (185.6 Mg/hr) of refuse having a lower heating value of 2159 Btu/lb (5.02 MJ/kg). The refuse furnace volumes of Units No. 28 and 29 are 17,655 cu ft and 17,443 cu ft (500 and 493 m<sup>3</sup>), respectively. The oil-furnace volume is 13,277 cu ft (376 m<sup>3</sup>) in both units.

The notable difference between the two Stuttgart units is the grate designs. Unit 28 is equipped with a Martin grate, while Unit 29 is equipped with a roller grate that evolved from the Dusseldorf design. Only bulky refuse is shredded before burning. Ferrous metals are removed from the residue magnetically.

#### *Essen-Karnap Plant*

Essentially three types of refuse are delivered to the plant: municipal refuse, bulky refuse, and industrial chemical refuse. A feature of this plant is that the raw refuse goes through a magnetic separation step before delivery to the furnace. From the metal separation step, the refuse is delivered by conveyor belt to the boiler house; generators deliver steam to five steam-turbines. The average lower heating value of the refuse is 2160 Btu/lb (5.02 MJ/kg); the highest noted was 2880 Btu/lb (6.70 MJ/kg). It was confirmed that this plant had never experienced any corrosion of tube surfaces in any unit. The only tube wastage attributable to refuse firing resulted when the refractory furnace was occasionally overloaded and the flame impinged on the water walls of the steam generator.

#### *Berlin-Ruhleben Plant*

This plant is three plants in one: a refuse-incineration plant, a clinker-processing plant, and a clinker-sintering plant. Steam is delivered to the Reuter power plant across the river. Superheated steam is delivered at or about 905°F (485°C) and 940 psig (6.48 MPa gage).

#### *Munich-South Plant*

The combined refuse/natural gas facility at this plant has potential capability for coal firing, although the bunkers and mills have not yet been installed in the space provided.

Only refuse collected by municipal trucks is brought to this plant. Bulky refuse is handled by special trucks equipped with built-in shredders. The residue is removed by conveyor belt and taken to a magnetic separator.

#### *Frankfurt am Main Plant*

The steam produced by refuse burning supplements that from oil-fired boilers. One of the unique features of the refuse-burning units is the changes to the vertical chute. As in Munich, trucks with built-in shredders were employed in lieu of stationary shredding equipment at the plant.

#### *Issy-les Moulineaux Plant*

This plant contains four refuse-fired, natural-circulation boilers, which use auxiliary fuel (oil) only while starting up. The rated plant capacity is 60 tons/hr (54 Mg/hr) while operating at steam conditions of 770°F (410°C) and 925 psig (6.38 MPa gage).

### *Ivry Plant*

The designed operating conditions are 875°F (468°C) and 1400 psig (9.65 MPa gage), using natural-circulation boilers. Like the Issy plant, it employs a reciprocating grate; refuse is the only fuel used, except during startup.

When completed, Ivry will be the world's largest refuse-fired steam generation facility, with the two furnaces able to handle 2400 tons/day (2.18 Tg/day). The completed plant cost will be \$30 million.

### *Nottingham*

Britain's first combined refuse incinerator and district heating plant is being constructed in Nottingham. The output will increase as the plant expands to 44 million Btu per hour (12.9 Mw) by 1980. At this time, approximately 170,000 tons (154.2 Tg) of refuse per year will be burned, providing up to two-thirds of the total heat output.

Steam from separately refined coal and refuse furnaces will be used for electrical generation and the supplying of hot water at 280°F (138°C) and 85 psi (586 kPa) to distribution mains. It is anticipated that the cost of heating and hot water will decrease by one-third.

### *Nashville*

Nashville, TN, has built a plant that handles 700 tons of waste per day (635 Mg/day) and provides energy for heat and air conditioning for 27 downtown office buildings (Mauldin, MA, is investigating a similar system.)

### *Philadelphia*

A Philadelphia plant scheduled for operation by the end of the 1970s will be constructed as a joint venture with Combustion Equipment Associates, Inc., and SCA Services, Inc. The plant is scheduled to process 2400 tons per day (2177 Mg/day), of industrial and commercial solid waste. It is estimated that 90 percent of the waste collected will be recovered as eco fuel.\*

### *East Bridgewater*

Combustion Equipment Associates have developed a process of deriving a solid fuel from solid wastes. The East Bridgewater, MA, plant uses 1200 tons (1089 Mg) per day of solid waste; the cost of construction was \$10 million. The solid waste is fed by conveyor systems to primary

---

\*Trade name of prepared fluff or dust refuse-derived fuel manufactured by Combustion Engineering.

shredders; the waste is then dried and classified in a separator and the fraction shredded again and sent through a mechanical separator; the final product is approximately 67.7 percent of the total amount of fuel. The heavy fraction is again further shredded and classified and the ferrous materials separated by magnet. The rest of the fraction is used as landfill. The refined combustible fraction is a grayish substance with popcorn consistency, 1/2 in. (12.7 mm) particle size, 7 to 10 lb/cu ft (112 to 160 kg/m<sup>3</sup>) in density, low in sulfur content, high in heating value (6900 Btu per pound [16.05 MJ/kg]), odor free, and stable for an indefinite storage period.

#### *Norfolk*

The Norfolk U.S. Naval Station, Norfolk, VA, is the only military facility now operating a refuse fuel to steam system. This is also the first U.S. application of a water-walled furnace employing waste heat recovery. This plant processes 180 tons (163 Mg) of mixed solid waste per day and releases about 50,000 to 60,000 lb/hr (22.7 to 27.2 Mg/hr) of steam at 275 psig (1.90 MPa gage).

#### *Others*

Other steam recovery incinerators in the U.S. include facilities in Providence, RI; Atlanta, GA; Meric, NY; Miami, FL; Oyster Bay, NY; Boston, MA; Oceanside, NY; Braintree, MA; New Hamilton, Ontario; and Montreal, Quebec.

Table 22 summarizes the current refuse firing systems.

#### Use of Refuse-Derived Fuel in Existing Boilers

Studies by CERL at more than a dozen military installations have shown that in some cases, it is economically attractive to use waste as an energy resource in relatively small-scale applications (solid waste streams from 20 to 60 tons/day [18 to 54 Mg/day]). The studies have demonstrated that small-scale applications have significant conceptual commonalities with larger, more proven, municipal-scale systems. The chief commonality is the desire for maximum return from a minimum investment. Plants using waste fuel systems seek to minimize investing in an essentially free "fuel" by minimizing the amount of processing it undergoes before entering the combustor. To reduce investment, existing boilers have been considered as candidate combustors for supplementary refuse-derived fuel (RDF) whenever possible.

#### *Generic Types of RDF*

The four major generic types of RDF are coarse, fluff, dust, and densified. The term "generic" refers to the form of final product

Table 22  
A Summary of Current Refuse Firing Systems

Summary	Municipal Refuse Quantities, Tons/Day (Mg/Day)	Coal/Oil/Gas*	Refuse, Tons (Mg)	Shredder or Separator Type*	Separate Prior to Burn*	Steam Output K-lb/hr (kg/sec)	Separation after Burn	Unique Features
Northwest Incin	1600 (1451)	C			FM		No	
Union Elec Co	300 (272)	C	10 (9.1)	H	FM		No	Plans to increase Refuse to 20 percent
Combustion Power	400 (363)		100 (90.7)	A	FM		No	\$2.50/ton (\$2.76/Mg) operating cost
Munich N, Blk I	660 (599)	C	40 (36.3)			220 (27.7)	FM	
Munich N, Blk II	1060 (962)	C	20 (18.1)			800 (100.8)	FM	
Dusseldorf	264 (239)	O				540.8 (68.1)	*Oil for start up 4 boilers	
Stuttgart	485 (440)	O				408.2 (51.4)	FM	Estimated Btu Content 2159 Btu/lb (5.02 MJ/kg)
Essen-Karnap					FM			3 Types of Refuse No corrosion
Berlin-R								3 Separate plants
Munich South		C			FM			No bulky refuse
Frankfurt		O						Truck shredders
Issy-Les M.	1440 (1306)	O						*Oil for startup
Ivry	2400 (2177)							World's largest; \$30 million total cost
Nottingham	465 (422)		66 (59.9)					Est. 1/3 reduction of heating costs
Nashville	700 (635)							
Philadelphia	2400 (2177)							90 percent recovery as Eco-fuel
East Bridgewater	1200 (1089)		67.7 (61.4)	A	FM			6900 Btu/lb (16.0 MJ/kg) processed
Fillingd	1200 (1089)					350 (44.1)		
Huntington								Fresh water from seawater
Norfolk	180 (163)		100 (90.7)			60 (7.6)		ODD facility

\* NOTES: C = Coal      H = Hammermill  
 O = Oil      A = Air Classified  
 G = Gas      FM = Ferrous Metals  
 G = Glass

from different processing lines. Coarse RDF is produced by shredding and classifying mixed solid waste. Top size of coarse RDF averages 6 in. (52 mm). The fuel performs best when fired in a stable bed with a moving grate as the stoking mechanism. Due to its loose consistency and low density, it is difficult to mix it adequately enough with conventional solid fuel to insure problem-free boiler performance.

CERL research has shown that when coarse RDF is moved from the air classifier through a second shredder and then through an agitated screening stage, the result is an improved fuel which can be pneumatically transported with fewer potential problems than coarse RDF. The improved product, fluff RDF, has an ash content somewhat lower than that of coarse RDF, due to removal of fines during the screening stage. Moreover, in comparison to coarse RDF, the pound for pound heating value of fluff RDF can be up to 8 percent higher. It has therefore been recommended that fluff, rather than coarse RDF, be considered for emerging municipal RDF systems. Current research is attempting to develop means of inhibiting passage of aluminum and light plastic through coarse and fluff RDF processing lines, and to improve means of removing glass and ceramic particles which tend to become imbedded in paper and cardboard particles during shredding.

Dust RDF is manufactured by adding embrittling and pulverizing steps to the generic fluff RDF manufacturing line. Dust RDF consists largely of cellulosic material that is highly fibrous, nonhygroscopic, and has unique flow properties. The use of sodium-sulfur compounds as embrittling agents has been successfully attempted and has shown that static fields can be almost totally eliminated from the fuel. Although there is no long-term operational experience with dust RDF, researchers are optimistic that it can be successfully suspension-fired like pulverized coal. The heating value of dust RDF is approximately 10 percent higher than that of fluff RDF, and contains approximately 25 percent less ash.

Densified RDF can be manufactured from coarse, fluff, or dust RDF by mechanical extrusion. Wet pulping pelletizing processes have also been successfully demonstrated, but are more costly. Fuel properties of densified RDF resemble those of the parent material. CERL tests have shown that 15 percent fluff-derived densified RDF will perform adequately over the short term when mixed with coal on a traveling chain grate stoker. Long-term performance characteristics are unknown.

The principal advantage of producing various forms of RDF is that heavier materials such as glass, ceramics, metals, and injection-molded plastics, which can have deleterious effects on internal boiler parts, are extracted. Additional modules can be added to various processing lines to further segregate recyclable materials. Revenue gained from the sale of salvaged materials can help pay back the investment required for RDF and the materials recovery process lines.

### *Boiler RDF Conversion*

Evaluating the capabilities of an existing military central steam generator for cofiring supplementary RDF usually involves comprehensive conceptual and quantitative redesign of the facility for a new, downgraded fuel. Required design is compared to existing design, and the extent to which new capital and hardware modifications are required is determined.

Experience has demonstrated that designers are characteristically conservative in boiler modification, fuel substitution, and waste fuel combustion. Designers have pointed out that in military-scale steam systems, supplementary RDF cofiring may be practicable on a short-term basis, but over the boiler life, there is substantially higher risk in continued RDF use, since the margin of designed combustor tolerance for a "worst fuel" is considerably narrowed. Currently, no long-term information pertaining to use of supplementary RDF in military-scale steam generators is available to either rebut or confirm these assessments.

### *Nature of RDF*

Average characteristics of RDF are dramatically different from those of coal. RDF moisture content compared to that of lignite, its ash content can be three times greater than that of coal, and coal has at least twice the amount of fixed carbon. Some types of RDF can contain a comparatively high percentage of volatile matter, which is often but not necessarily more reactive than that of coal. RDF oxygen and nitrogen contents are approximately twice as high as for most coals; hydrogen content is approximately the same, and carbon content is less. RDF has from one-third to one-half the heating value of most coals. Although average RDF is generally low in sulfur, this advantage is more than offset by the presence of halogens and lead and zinc compounds. On the whole, RDF is potentially more corrosive. Ash fusion temperatures are lower (due to glass, ceramics), and hence, the propensity for slagging and fouling is greater.

The variability of solid waste has a pervasive effect on all elements of RDF system design. System development must often combine procedures used separately for incinerators and boilers that are almost mutually exclusive. Incinerators are usually sized for peak loads, since they must meet a continuing waste disposal requirement. Boilers, however, are sized for optimal performance on a fixed amount of design fuel.

The extent of processing necessary to produce any form of RDF has the net effect of making the properties of each individual load fed to the furnace closer to the statistically average load. Processing, however, adds considerable value to an essentially free fuel but, because it is essentially refinement, it does not totally solve

a waste disposal problem; from 20 to 40 percent of the mass input into RDF processing lines is rejected and therefore persists as a waste disposal requirement. Value added to solid waste in RDF processing lines is in the form of additional capital and O&M costs. CERL studies have shown that labor is a significant cost element over even a modest economic life: nearly all developing RDF processing lines are labor-intensive, and satisfactory operation is contingent upon more costly skilled personnel.

#### *Fuel-Burning Equipment*

It now appears that if RDF is used in relatively small military boilers as a supplementary fuel, it will usually be cofired with coal on a moving grate. This method is one of the more reliable methods of firing waste fuel.

A burner is functionally defined as a device to mix air with fuel so that it ignites and burns freely. In the types of military boilers considered for RDF use, the furnace is the "burner," serving the dual purposes of mixing chamber and heat exchanger. If boiler rating is to be maintained while a lower grade fuel is being fired, a greater quantity of fuel must be fed to the furnace per unit time. The required fuel feed rate increases rapidly with small decreases in fuel heating value. Maintaining optimum fuel bed depth at higher fuel feed rates requires increasing stoker speed. Increased stoker speed decreases fuel residence time, resulting in increased heat losses; in addition, burning particles may enter the ash hopper, creating hazards of fire and explosion. Two attempts have been made to reconcile the mutually exclusive requirements of both increasing and decreasing stoker speed: (1) replacing the stoker with a grate that enhances mechanical mixing, and (2) broadening and deepening the furnace to provide a longer effective fuel path through the combustion zone.

The nature of RDF particles is very important to stoker and furnace performance. Currently manufactured RDF pellets relinquish their structural integrity in the furnace comparatively rapidly, causing the probability of grate fouling to be higher than with coal firing alone.

Combustion air requirements for cofiring RDF may exceed those for coal by as much as 50 percent. Increased undergrate air velocity disrupts fuel bed integrity, and lighter particles of RDF may be blown into the furnace volume. Carryover of burning elements into screen tubes and downstream convective areas may be reasonably anticipated.

Distance of flame travel required for complete combustion of RDF is another frequently overlooked critical parameter in evaluating the RDF capability of military-scale boilers. When cofiring RDF, flame heights 20 to 30 percent greater than those experienced with coal are

not unusual. By increasing underfire and overfire air to meet combustion requirements, the flame is pushed further up into the furnace volume. Impingement of the flame on furnace backwall, roof, and possibly exposed screen tube sections, as well as accelerated surface wastage in these areas may be anticipated. Ameliorating this problem usually involves elevating the boiler several feet.

Increasing combustion air has several other major effects. First, a greater absolute amount of fuel heat is lost to heating the cold excess air entering the furnace and evaporating the moisture it contains. Heat losses to moisture are major, since large quantities of air are required for combustion and RDF moisture content can be up to three times that of the design fuel. Heat losses directly engendered by substituting RDF reduce the relative economy, and hence the major justification, of using the waste fuel. Gas temperatures leaving the furnace may be between 5 and 10 percent less than the designed optimum due to heat losses and the fact that flame temperature with RDF is substantially less than with the design fuel. Secondly, gas mass flow rates and velocities through the furnace may be higher than design permits. With temperature nonuniformity, gas flow changes develop new flow fields in the furnace which cannot be analytically defined or predicted. The nature and effects of new flow fields with increased gas particulate loading (resulting from incomplete RDF combustion, excessive turbulence, and other phenomena) on furnace surfaces can be estimated only by experienced designers after thorough study.

#### *Convective Area*

Military boilers candidate for coal/RDF use usually have screen tubes after the furnace to cool furnace exit gases before they enter the more closely spaced boiler convection surface. Screen tube performance is affected by gas flow rate and, more importantly, gas temperature. Gas temperature drop per row of tubes can be up to 10 percent less than optimal. Gas velocity through the free gas area in the screen bank can be high enough to cause accelerated surface erosion by fly ash particles carried in the stream. Baffles can be added to ameliorate this problem in erosion-prone zones, but they are an empirical measure often taken only when signs of damage appear. Sometimes, tubes in the screen bank can be removed to enlarge the free gas area, with the screen tube bank lengthened to compensate for the loss of absorbing surface area.

Gas velocities to the boiler may exceed design tolerance. As gases lose their heat to absorbing surfaces, their ability to transport particulate matter is greatly reduced. Existing residue removal hardware is usually inadequate to handle the larger residue load. Sparklers carried through from the furnace create fire and explosion hazards.

Although gas velocities to the boiler are high, temperatures are often lower than the design calls for, so a substantially lower log mean temperature difference across the convective bank is typical. With the increased moisture in the combustion products caused by firing RDF, the rate of nonluminous radiation transfer can be substantially higher than optimal; however, the rates of convective transfer and total heat transfer are lower. The existing boiler absorbing surface area may be completely inadequate for maintaining acceptable thermal balances. Moreover, tube spacing may be insufficient to prevent fouling by the increased quantities of particulate matter being transported more rapidly into the section. The possibility of accelerated surface erosion is great under these conditions.

Every indication points to the necessity of resetting tubes in the boiler section if RDF is to be co-fired economically in small boilers. Minimum practical spacing of tubes is determined by draft loss, gas velocity, and erosion potential. Co-firing RDF is certain to substantially increase each of these parameters.

#### Auxiliaries

Placement of sootblowers is imperative if the furnace and boiler are to be operated satisfactorily. The fuel ash content and ash fusion temperature determine the number of sootblowers required and their locations. With the higher ash content and lower ash fusion temperature associated with RDF, sootblowing requirements are generally greater than for coal alone. Use of RDF as a supplementary boiler fuel will usually require additional sootblowing capability and possible re-location of existing ports.

When co-firing RDF, furnace draft loss due to increased mass flow can be greater than that when firing coal alone, and fan requirements must be examined closely. Forced draft (FD) fan size is a function of both moisture content of fuel and air and of downstream tempering air requirements. With higher moisture content, less tempering air is admitted downstream, and more air must be forced directly into the furnace through the FD fan. If a boiler is to be converted to a downgraded fuel, FD fans installed for the higher grade design fuel normally must be replaced with units of larger capacity and power consumption. ID fan requirements are determined essentially by ash load and ash composition. The type of air pollution control equipment used and the tendency for convective surfaces to plug and foul set the limits on ID fan size and static requirements. Generally, ID fans will require replacement with larger units if RDF is used. Due to higher ash loading and increased abrasiveness of the ash, the ID fan will be subject to more wear, increasing required maintenance.

Higher mass flow rates through the furnace and boiler normally will require reevaluation of stack parameters. The height of the stack must usually be increased, but it is not uncommon to encounter

cases in which a completely new stack, with greater cross-sectional area, must be installed.

Use of a higher ash fuel which requires greater quantities of combustion air normally causes an adverse shift of the particulate collection efficiency of existing air pollution control equipment. Existing equipment is likely to be inadequate for reducing emissions to acceptable levels. Normally, new air pollution control hardware must be installed, the design of which is responsive to higher particulate load, higher gas flow rate, size distribution of the particulates, potential for cold end acid attack, and the ash's unique chemical consistency.

#### *Surface Effects*

A furnace is a large, heterogeneous turbulent chemical reactor in which fuel is mixed with air to produce high-temperature combustion products which lose their heat to evaporating water. For a system to function satisfactorily, surfaces must be kept clean and intact. Fouling, slagging, and corrosion cause deleterious effects such as poor system performance and fuel economy.

Fouling refers to the accumulation of ash and residue in gas passages or on heat-absorbing surfaces which usually results from undesirable restrictions to the flow of gas or heat. The rate of deposition is strongly influenced by the quantity of ash passing over the surface per unit time. With the higher ash content found in RDF, there is apt to be a greater tendency for surface fouling than when only coal is fired. The rate of fouling also depends on the size distribution of the residue. For larger particles, whose path of travel is less affected by changing gas direction and velocity, deposition occurs mainly by inertial impaction. Because of the heterogeneous nature of the particle suspension and the fact that gas velocity, temperature, ash concentration, and size distribution are always changing, it is likely that numerous deposition processes occur simultaneously.

Slag is essentially molten or fused ash, and the term "slagging" refers to fused slag deposits which form on surfaces. Slagging normally occurs on surfaces exposed to radiant heat (the hottest part of the furnace) and is associated with the transport of molten or sticky particles and the formation of local, dense, hard deposits. The principal deleterious effects of slagging are a reduction of heat transfer due to build-up on absorbing surfaces and surface wastage. Ash fusion temperatures of RDF are substantially lower than those of coal, due to the presence of glass and iron-aluminum compounds. It is not unusual to experience severe slagging problems with RDF at temperatures typically encountered in small-scale furnaces.

Three corrosion mechanisms can be expected to occur in any furnace fired with coal and coal/RDF mixtures. First, carbon monoxide

and hydrogen sulfide are produced as products of partial combustion in a reducing atmosphere and cause tube failure by directly reducing the protective iron oxide layer on the tubes. The second mechanism, attributed to halogens present in relatively great quantities in RDF and to a lesser extent in coal, is direct attack on metal by hot chloride compounds. Finally, low-temperature corrosion occurs at cold ends of systems when the flue gas contacts surfaces whose temperatures are below the dew point of corrosive constituents in the gas. Most designers agree that corrosion problems experienced when burning refuse or RDF result from the presence of chlorine, sulfur, lead, zinc, sodium, and potassium in the flue gases and in ash deposited on surfaces, and that the persistence of a fluctuating oxidizing/reducing atmosphere is a significant factor in metal wastage.

#### *Storage and Flow of RDF*

Design requirements for storage and flow have been one of the most overlooked factors in the evaluation of RDF systems. It has frequently been taken for granted that if a military central steam plant has solid fuel handling and storage facilities (which most often were designed for a particular coal), then these facilities can adequately be used for various forms of RDF. However, substantial field experience in small-scale RDF systems has indicated that the opposite is true.

The flowability of a solid is affected by the particle's size and nature, bulk density, moisture content, temperature, and time of storage. Together, these factors determine whether any form of RDF will be used successfully in coal-handling systems.

The essential flow requirement for RDF is mass flow rather than funnel flow, where a stagnant volume of solid forms in a bin around its outlet. Mass flow has no stagnant volume, and therefore the potential of biological and chemical degradation of RDF is minimized. A bin designed for mass flow provides for uniform discharge rate at uniform material density, minimizes material segregation, has increased effective storage capacity (due to no stagnant volume), and permits reliable operation of the system into which it is integrated.

Whether a solid will flow freely from a hopper depends essentially on its flowability and the flow function of the hopper. The flow function of a particular hopper is related to its geometry, the size of the outlet, and the presence of wall obstructions. Highly flowable solids such as dry sand will flow easily from any hopper designed for coal, since dry sand cannot be consolidated at pressures normally encountered in coal bins. If moisture is added to the sand, it gains strength and may become consolidated more readily under low pressure, thus restricting its flowability. A flow aid such as a bin vibrator may be used to accommodate flow.

When conducting a test of RDF in a small-scale boiler, CERL researchers placed a substantial mass of densified RDF into a hopper

designed for bituminous coal. Removal of the RDF was extremely difficult. Subsequent analyses showed that several variables were important in the no-flow condition. The RDF particle size was substantially different from that of coal (shredded paper with 1/4-in. [6.4-mm] top size vs. 1 1/2-in. [38-mm] coal). The RDF bulk density was only 40 percent that of the coal, and moisture content was nearly three times that of the fuel for which the hopper was designed. The RDF was highly fibrous, and as it sat in the hopper, the pellet structure rapidly deteriorated under modest pressures, forming a solid mat strengthened by lacing and intertwining of the fibers. Migrating moisture added strength to the bottom of the mass, further reducing flowability in critical areas near outlets. Moisture and heat in the RDF induced accelerated chemical and biological activity, which resulted both in harborage of insects and combustion within the bottom mass. Rapping the bin and hopper and using a vibrator did not improve flow, but rather caused additional matting of the RDF. The problem was solved by saturating the RDF with water; fluidization increased flowability, and the mass was washed from the hopper.

Further analyses and field inspections have shown clearly that hoppers designed for coal at military installations cannot be used to store RDF. Analysis has also indicated that most hoppers are poorly designed for the coal they now handle, which increases the possibility of severe flow problems when a coal/RDF mixture is placed in them. Presently, no form of RDF is being produced economically that can be handled reliably in the type of coal hoppers found at military installations. This critical aspect in evaluating RDF capabilities at military-scale steam plants is currently being studied, but it now appears that use of RDF at military plants will require comprehensive redesign and modification or replacement of all solid fuel handling equipment used to move fuel from delivery to the furnace.

## APPENDIX A:

### COMBUSTION STOICHIOMETRY

#### Theoretical Oxygen and Air for Combustion

The minimum amount of oxygen or air required to sufficiently burn a given weight of fuel is called the theoretical oxygen or air. The theoretical oxygen can be calculated from the ultimate analysis of the fuel by the following equation:

Theoretical oxygen, cu ft/lb of fuel

$$= 359 \left( \frac{C}{12} + \frac{H_2}{4} - \frac{O_2}{32} + \frac{S}{32} \right) \quad [\text{Eq A1}]$$

where C, H<sub>2</sub>, O<sub>2</sub>, S are the fractions by weight of these elements in the fuel. The coefficient 359 is the volume in cubic feet of 1 mole of oxygen at 32°F (0°C) and 1 atmosphere.

The composition of air is approximately 0.232 O<sub>2</sub> and 0.768 N<sub>2</sub> by weight, or 0.21 O<sub>2</sub> and 0.79 N<sub>2</sub> by volume. The volume of air is obtained by dividing the volume of oxygen by 0.21. The weight of oxygen or air is obtained by multiplying volume by density. The density of air and oxygen at 32°F (0°C) is 0.081 and 0.089 lb<sub>m</sub>/cu ft (1.297 and 1.426 kg/m<sup>3</sup>), respectively.

A mixture of theoretical air and fuel is termed a chemically correct or a stoichiometric mixture. Table A1 gives the theoretical air requirements on the basis of the higher heating value for coal and fuel oil.

#### Products of Combustion

The gaseous products arising from the complete combustion of a fuel are CO<sub>2</sub>, H<sub>2</sub>O, and if sulfur is present, SO<sub>2</sub>. Accompanying these are the nitrogen brought in with the air and the oxygen in the excess air. The presence of carbon monoxide indicates incomplete combustion. The products of combustion by weight in lb/lb of fuel can be calculated by the following formulas:

$$\left. \begin{aligned} CO_2 &= 3.66 C \\ H_2O &= 8.94 H_2 + H_2O + (\text{total air supplied*/lb fuel}) \times (\text{humidity ratio of air, lb water/lb air}) \\ SO_2 &= 2.00 S \\ N_2 &= (\text{total air supplied/lb fuel}) \times .768 + N_2 \end{aligned} \right\} \quad [\text{Eq A2}]$$

\*Total air supplied = theoretical air plus excess air.

Table A1  
Theoretical Air for Combustion\*

Fuel	Combustion conditions at zero excess air	
	Atmospheric air required (1b/10,000 Btu)	
	Range	Average
<b>Anthracite:</b>		
New Mexico		7.83
Colorado		7.85
Pennsylvania	7.81 - 7.93	6.87
Semianthracite	7.68 - 7.82	7.74
<b>Bituminous coal:</b>		
Low-volatile	7.62 - 7.76	7.69
Medium-volatile		7.77
High-volatile A	7.51 - 7.73	7.63
High-volatile B	7.56 - 7.73	7.66
High-volatile C	7.54 - 7.67	7.60
Subbituminous coal	7.56 - 7.57	7.56
<b>Lignite:</b>		
North Dakota		7.47
Texas		7.52
<b>Petroleum oils:</b>		
Gasoline (60° API)		7.46
Kerosene (45° API)		7.42
Gas oil (30° API)		7.45
Fuel oil (15° API)		7.58

\* Fuels and Combustion Handbook, p 355.  
\*\* 1 lb/10,000 Btu = 0.430 Kg/10 MJ.

where C, H<sub>2</sub>, H<sub>2</sub>O, S, and N<sub>2</sub> represent the fraction by weight of these quantities in the fuel.

#### Excess Air for Combustion

More than the theoretical amount of air is necessary in practice to achieve complete combustion. This excess air is generally expressed as a percentage of the theoretical air. The amount of excess air can be calculated from the percentage by volume of the N<sub>2</sub>, CO, and CO<sub>2</sub> in the flue gas by the following formula:

$$\text{percent excess air} = \frac{O_2 - 0.5(\text{CO})}{0.264(N_2) - O_2 + 0.5(\text{CO})} \times 100 \quad [\text{Eq A3}]$$

The percentage by volume of CO, O<sub>2</sub>, CO<sub>2</sub>, and N<sub>2</sub> (by difference) can be determined by an Orsat apparatus or other volumetric methods.

APPENDIX B:

CONTROL OF AIR POLLUTANTS  
FROM COMBUSTION PROCESSES

Stationary power sources use boilers with steam turbines, diesel engines, or gas turbines. Each of these burns a fuel, coal, or petroleum, which yields both combustion byproducts and heat. Some of these byproducts have deleterious effects on the environment, are aesthetically undesirable, and are dangerous to human health.

Coal and petroleum contain variable levels of sulfur, nitrogen, and ash. Oxidation of sulfur and nitrogen forms gaseous pollutants (sulfur dioxide and nitrogen oxides) which damage the respiratory and nervous systems. Ash, the noncombustible matter in fuel, is suspended particulate matter released during the oxidation of the combustible matter. Most of the suspended ash is large particles which may be visible as aesthetically displeasing smoke; however, the largest number of the particles are small enough either to remain suspended in the atmosphere for long periods of time or to be deposited in the respiratory system where they plug or coat the respiratory passages.

Because of the hazards associated with these air contaminants, Federal, state, and local governments have enacted air pollution laws and compliance regulations which must be met by stationary combustion units. This appendix presents the types, application, availability, and effectiveness of state-of-the-art control techniques for stationary source emissions of particulates, nitrogen oxides, sulfur dioxide, carbon monoxide, and hydrocarbons.

Application of Control Devices

Devices which take advantage of certain physical, chemical, and electrical properties of the pollutants and the carrier gas stream are currently used to clean contaminated exhaust gas streams from stationary power sources. A control device's effectiveness is measured by the collection efficiency--the percentage of the pollutant retained by the collector by weight.

Particulate Control

Particulate control devices are generally categorized by particle capture mechanism. Several types of particulate collectors are commercially available which have shown a high degree of dependability when an application has been properly selected.

### *Dry Collection*

Dry collectors include gravity settling chambers, centrifugal collectors, electrostatic precipitators, and fabric filtration.

Settling Chambers. Gravity settling chambers are formed in an expanded section of the exhaust duct. The increase in the duct's cross-sectional area decreases the carrier gas velocity. Gravity then becomes the principal force acting on the particles, causing them to settle. Low velocities minimize particle re-entrainment (recapture by the carrier gas stream).

The collection efficiency of settling chambers depends on the particle retention time in the chamber and the particle settling time. The particle retention time is a function of the flow and chamber dimensions, and the particle settling time is a function of particle size, shape, and density. The effectiveness of gravity settling chambers is limited by the relationship between chamber size, available space, and the allowable pressure loss through the chamber. The chamber size limitation restricts the chamber's ability to collect the smaller, slower-settling particles; therefore, gravity settling chambers have relatively low collection efficiencies--typically 30 to 40 percent for the range of particle sizes usually encountered in exhaust gas streams (usually 1 micron or more). However, they can be applied effectively as primary collectors for removing larger particles, while secondary collectors can be used for the smaller particles.

Cyclones. Centrifugal collectors, commonly called cyclones or rotocyclones, use centrifugal force to separate the particulate matter from the gas stream. The particulate-laden gas stream enters the cylindrical body of the collector tangentially and exits through a central discharge opening at the top. The particulate matter, which is separated from the gas stream by a combination of centrifugal and gravitational forces, moves down and is removed at the lower end.

Because particle motion and collection are dependent on centrifugal force, frictional drag, and gravity, the effectiveness of centrifugal collectors is sensitive to the particulate size range. Low-efficiency cyclones have a typical effectiveness of 50 to 80 percent for particle sizes of 5 microns or more. They are very effective as primary collectors of large particles (60 microns or more). Conventional medium-efficiency cyclones are the most widely used and have a typical effectiveness of 80 to 95 percent for the same particle size range as low-efficiency collectors. They are effective as primary or secondary collectors for particles of 50 or more microns but remove only a small fraction of 20- to 50-micron particles. High-efficiency cyclones have an efficiency range of 95 to 99 percent. They are effective for removing particles of 20 or more microns and for partial removal of 10- to 20-micron particles.

Frictional and dynamic energy losses in the carrier gas cause a pressure drop in cyclones of typically 1 to 8 in. of water (.25 to 1.99 kPa). Frictional losses result from the drag force between the gas stream and cyclone surface; energy used to spin the gas stream causes dynamic losses. Since collection efficiency depends on the centrifugal force of the spinning gas, there is a trade-off between a cyclone's effectiveness and pressure drop. This relationship limits the use of high-efficiency cyclones.

The principal advantages of conventional cyclones are compactness, low pressure loss for a relatively high effectiveness, and high gas-handling capacity; major limitations are the plugging tendency, rotor imbalance for impeller-driven cyclones, and temperature effects on bearings and seals.

**Electrostatic Precipitators.** Electrostatic precipitators consist of several rectangular or cylindrical grounded collector tubes with an electrode (wire) running along the tube centerline. The particulate matter becomes electrically charged by ionic bombardment while passing through direct-current corona and is then subjected to an electric field which forces the particulate matter outward toward the grounded collector plates. The corona is established by freeing electrons in the carrier gas stream with an electric field. Due to an electrically induced motion, these free electrons collide with gas molecules to form ions and additional free electrons. The ions may charge the particles by interception, impaction, or diffusion.

Charged particles then migrate toward the grounded collector plate. The collected charged particles are removed periodically to prevent both particle re-entrainment and the formation of a back corona from an accumulation of highly concentrated electrical charges at the collector wall.

There are two basic types of electrostatic precipitators. The high-voltage precipitator has a negative potential between the center-line electrode and the grounded collector tube, which develops a negative corona. The electrical characteristics of a negative corona cause the applied voltage to be relatively high--typically 30 to 100 kV before sparking. The low-voltage precipitator has a positive potential between the electrode and the grounded collector, which forms a positive corona requiring a lower applied voltage--typically 10 to 13 kV--to prevent sparking.

The effectiveness of electrostatic precipitators--typically 95 to 99 percent--is sensitive to overloading, the spark rate (determined partly by the applied voltage), and the electrical conductivity of the particles. The latter consideration has created a problem in removing particulates formed during the combustion of low-sulfur coal. However, the electrostatic precipitator's effectiveness on these

slightly conductive particles can be enhanced by injecting an electro-negative element into the carrier gas. The electronegative elements commonly used include halogens, oxygen, and sulfur dioxide.

The advantage of electrostatic precipitators is their effectiveness in removing small particles; the major disadvantage is their inability to ionize submicron particles (those presenting a health hazard).

Fabric Filtration. Fabric filtration uses a chamber (commonly called a baghouse) containing one or more woven fabric bags. As the particle-laden gas passes through the porous fabric, the particles are deposited on the fabric fibers. This collection process forms a packed, porous filter cake, which enhances the filtration; however, the developing filter cake also increases the pressure drop across the fabric filter, so the filter bag must be cleaned periodically. Fabric filters are normally cleaned by reversing the air flow, and mechanically or pneumatically shaking the bags.

There are two basic types of fabric filtration collectors: continuous and discontinuous. The most prevalent type is the continuous-operation baghouse, a series of filter bags from which the dirtiest bag is removed periodically, cleaned, and replaced. The discontinuous-operation baghouse consists of a series of filter bags which are cleaned simultaneously. While these filter bags are being cleaned, the particle-laden gas must either be passed through another collector or exhausted to the atmosphere.

The advantages of baghouses are their collection efficiency, which is typically greater than 99 percent, and their effectiveness in removing submicron particles. Their major disadvantages, a result of their fabric substance, are susceptibility to temperature increases and corrosion; however, synthetic fabric bags, such as fiberglass, nomex, and teflon increase the operational temperature limits.

#### *Wet Collection*

Wet collectors introduce liquid droplets, usually water, into the exhaust stream to enhance the removal of particulate matter by "wetting." Particle wetting increases a particle's effective size, which facilitates its collection by impingement on a collecting surface, centrifugal removal in a cyclone, or gravity settling. These collected wet particles form a liquid film on the collector surface which limits particle re-entrainment. This entire operation is referred to as "scrubbing."

The wet collectors available are generally two-stage systems: particle wetting and mechanical collection. Wet scrubbers may be classified into three categories: (1) cross-current scrubbers, in which the liquid-droplet motion is perpendicular to the flow of the particle-gas stream; (2) co-current scrubbers, in which the liquid-droplet motion is parallel and in the same direction as the particle-gas

flow; and (3) counter-current scrubbers, in which the liquid-droplet motion is parallel to and in opposition to the particle-gas flow.

Mechanical collection normally uses settling chambers, cyclones, and impingement surfaces, which include plates, rotating blades, and packed towers. Impingement plates are drilled plates stacked with the orifices off-center to improve particle impaction. Rotating blades strike the wet particles, which adhere to the wet film on the blades. Packed towers have coarsely or finely packed beds consisting of granular materials with large surface areas, a low weight per unit volume, and a large, free cross-section. The packed bed forms pores which collect wet particles by impaction and interception.

Due to the dependency of particle collection on contact between the particle and the liquid droplets, the effectiveness of wet mechanical collectors is directly related to the contact power forcing the gas-particulate stream through the collector and generating the liquid spray. Although collection efficiency varies widely with design, it is typically 90 to 95 percent. Scrubber wastewater may require treatment before recirculation or discharge to a receiving water body.

The advantages of wet collectors are a constant pressure drop, small space requirements, and the ability to handle corrosive, high-temperature, moisture-laden gases.

#### Control of Nitrogen Oxides

The term nitrogen oxides, or  $\text{NO}_x$ , refers to either or both of two gaseous oxides of nitrogen: nitric oxide ( $\text{NO}$ ), and nitrogen dioxide ( $\text{NO}_2$ ). These substances are involved in photochemical reactions in the atmosphere (resulting in formation of smog) and have undesirable physiological effects.

There are two approaches to control of nitrogen oxides: (1) modifying the sources so that the amount of nitrogen oxides emitted to the atmosphere is reduced, and (2) extracting the pollutants from the exhaust gas stream before it enters the atmosphere. Presently, no economically feasible method has been found to remove  $\text{NO}_x$  from stack gas.

The key to reducing  $\text{NO}_x$  emissions is modification of the design features and operating conditions of the combustion process, such as lowering the flame temperature, decreasing the amount of excess air, and altering the time-temperature profile in the furnace. This technique is regarded as the most promising method of controlling  $\text{NO}_x$  emissions because of its simplicity and low cost. However, it should be noted that the conditions that decrease  $\text{NO}_x$  emissions may tend to increase carbon monoxide and hydrocarbon emissions and also to increase fuel consumption.

Modifications in the operating conditions of the combustion process include methods such as low excess air combustion, two-stage combustion, flue gas recirculation, and steam and water injection.

The low excess air combustion method supplies as many of the stoichiometric requirements of air for complete combustion of fuel as are permitted by the nature of the combustion process.

In two-stage combustion, only 85 to 95 percent of the stoichiometric air needed for combustion is introduced at the burner with the fuel; the remainder enters as tertiary air through auxiliary ports in the walls of the firebox.

The flue gas recirculation method recycles a portion of the flue gases back to the combustion chamber. The effect of recycling depends on the point of injection into the combustion chamber and the quantity of gas recycled. The maximum effect is achieved when the recycled gas is injected directly into the primary flame zone, because it results in lower flame temperature and a lower amount of excess oxygen.

Steam or water injection also results in a lower flame temperature. Steam can be injected by the atomizers in gas- or coal-fired boilers equipped for standby oil firing with steam atomization.

The specific design and configuration of a burner influences the amount of NO<sub>x</sub> formed. For example, the ring-type burner produces less NO<sub>x</sub> than the radial-spud type and the spud type. The spray angle in oil atomizers can affect NO<sub>x</sub> formation; however, the results of investigations are contradictory. Burners such as the cyclone and vortex types, which operate under highly turbulent and intense conditions, can reduce the amount of NO<sub>x</sub> by decreasing the level of turbulence. However, investigations have shown that at certain decreased turbulence levels, the flame conditions are unsatisfactory.

The spacing and location of burners affect the amount of NO<sub>x</sub> emissions. Flames of closely spaced burners tend to interact with each other, which increases flame temperature and therefore NO<sub>x</sub> emissions. In a tangentially fired boiler, the burners (located in the corners) fire on a tangent to an imaginary circle in the center of the furnace. As a result, individual burner flames have very little opportunity to interact with each other. Tangential firing can reduce NO<sub>x</sub> by one-half in comparison to horizontal firing.

#### Control of Sulfur Dioxide

There are three broad classifications of desulfurization equipment: (1) throw-away scrubbing, in which the recovered sulfur is disposed of; (2) regenerable scrubbing, in which the recovered sulfur is processed into a saleable commodity, such as elemental sulfur or

sulfuric acid, and the absorbent is regenerated; and (3) dry processes, in which the sulfur dioxide is removed without using liquid contacting.

These desulfurization processes are capable of achieving 75 to 85 percent removal. The availability of equipment within these three broad classifications is extremely variable.

#### *Throw-Away Processes*

The throw-away processes include lime-limestone scrubbing and double-alkali scrubbing. In lime-limestone scrubbing, the sulfur-dioxide-laden gas stream is forced into contact with a slurry of calcium oxide-calcium carbonate. The sulfur dioxide chemically reacts with the calcium oxide-calcium carbonate to form calcium sulfate, an insoluble waste sludge. The effectiveness of the lime-limestone scrubber is typically 70 to 90 percent. The advantages of lime-limestone scrubbing are low operating and capital costs, and the complete removal of sulfur dioxide and particulate matter. The major disadvantages are the large accumulations of waste sludge, and inherent design problems such as scaling, plugging, and erosion.

The double-alkali scrubber, developed to resolve the alkali (lime-limestone) scrubber scaling problem, uses a two-stage reaction. A soluble alkali-sulfur oxide complex is first formed in the scrubber and then removed by a secondary reaction in another vessel. Typically, the effectiveness of double-alkali scrubbers is 90 to 99 percent. The advantages and disadvantages of double-alkali scrubbers are similar to those of the lime-limestone scrubber, except that the double-alkali scrubber eliminates scaling, plugging, and erosion.

#### *Regenerable Processes*

The following regenerating processes are most attractive, because they create a saleable product, regenerate the sulfur dioxide absorbent, and produce relatively small quantities of wastes.

The magnesium-oxide scrubbing system is similar to lime-limestone scrubbing except that magnesium oxide replaces the calcium oxide. The magnesium sulfate sludge formed may be calcined to release the sulfur and regenerate the absorbent. The effectiveness of this process is typically 90 percent; however, the process lacks reliable, long-term operational validation.

The Wellman-Lord absorption process uses a sodium-sulfite absorbent solution. The spent absorbent, rich in sodium bisulfite, is processed in a steam-heated evaporator to regenerate the absorbent and release the sulfur dioxide for conversion to a saleable product. The effectiveness of this process is typically greater than 90 percent. However, this process is sensitive to the formation of inactive sodium sulfate

from the active sodium sulfite by sulfur trioxide absorption and sulfur oxidation. The sodium sulfate must be purged from the system and disposed of.

The citrate process uses an alkali-citrate scrubbing liquor to remove the sulfur dioxide. The spent liquor is reacted with hydrogen sulfide to produce elemental sulfur and regenerate the scrubbing liquor.

#### *Dry Processes*

The dry processes are those like the Monsanto Cat Ox process, which catalytically oxidizes the sulfur dioxide to sulfur trioxide. The sulfur trioxide is easily condensed into weak sulfurous and sulfuric acid and collected in an absorption tower or scrubber. The acid is usually 80 percent pure and can be used for fertilizer production.

The catalytic bed used in this process must be protected from particulate matter; therefore, an electrostatic precipitator is normally used before the Cat Ox process. The effectiveness of the Monsanto Cat Ox process is typically 85 percent for sulfur dioxide and 99 percent for particulates. The major disadvantages of this process are the lack of operational reliability and the production of a product that is saleable only in certain areas.

#### Control of Carbon Monoxide (CO)

Carbon monoxide is formed when less than the theoretical amount of oxygen required for complete combustion of carbonaceous materials is supplied. It can also be formed by a poor air and fuel mixture even if the total air supply is excessive.

The most practical technique for controlling carbon monoxide emissions from power plants is the proper design, application, installation, operation, and maintenance of the combustion equipment and auxiliary systems.

Low carbon monoxide emission levels can be obtained by combustion equipment designs which result in sufficient air for combustion, intimate mixing of air and fuel, a high combustion temperature, sufficient reaction time, and low effluent temperature. Insufficient air always causes CO formation; however, too much air may do the same by lowering flame temperature. Good mixing of air and fuel, long reaction time, and slow cooling of combustion gases promotes a more complete oxidation of CO to CO<sub>2</sub>. High flame temperatures are desirable; however, flame temperatures above 3000°F (1650°C) are conducive to formation of NO<sub>x</sub>.

Combustion units should be operated within their design limits and according to the recommendations of the manufacturers. Operating in excess of the design limits--overloading--causes excessive CO emissions.

Combustion units and components should be continuously maintained to meet design specifications. For example, defects in oil burner operation such as clogged or dirty burners, clogged flue gas passages, insufficient atomizing pressure, poor draft, and impaired air supply would cause high CO emissions. CO monitoring systems are helpful in indicating the need for maintenance.

#### Control of Hydrocarbons

Hydrocarbons and other organic materials may be emitted if combustion is incomplete. Stationary fuel combustion equipment is not a serious source of hydrocarbon emissions when it is properly designed and operated.

As in the case of CO control, the most practical technique for control of hydrocarbons and other organic materials is increasing combustion efficiency. This can be achieved by proper design, application, installation, operation, and maintenance of the combustion equipment and auxiliary system.

## REFERENCES

- Baumeister, T. and L. S. Marks, eds., *Standard Handbook for Mechanical Engineers*, 7th ed. (McGraw-Hill, 1973), pp 10-52--10-82.
- Carmichael, C., ed., *Kent's Mechanical Engineers Handbook, Design and Production Volume*, 12th ed. (John Wiley and Sons, Inc., 1969).
- Coal Reserves of the United States*, U.S. Geological Survey Bulletin 1136 (U.S. Geological Survey, 1961).
- Conn, A. L., "Low Btu Gas for Power Plants," *Chemical Engineering Progress*, Vol 69, No. 12 (December 1973), p 56.
- Corey, R., "Measurements and Significance of the Flow Properties of Coal Ash Slag," *U.S. Bureau of Mines Bulletin 618* (1964).
- Federal Specification VV-F-815C, *Specification for Burner Fuel Oil* (1972).
- Flammable and Combustible Liquids Code*, NFPA No. 30-1973 (National Fire Protection Association [NFPA], 1973).
- "Forms of Sulfur in U.S. Coals," *U.S. Bureau of Mines Information Circular 8301* (1966).
- "Free-swelling and Grindability Indexes of United States Coals," *Bureau of Mines Information Circular 8025* (Bureau of Mines, 1961).
- Fryling, G. R., ed., *Combustion Engineering* (Combustion Engineering, Inc., 1966), p 16-12.
- Giddings, J. Calvin, "Average Sulfur Content of U.S. Coal Deposits," *Chemistry, Man and Environmental Change*, Fig. 7-12 (Harper & Row, 1973), p 262.
- Hathaway, S. A. and H. G. Rigo, *Technical Evaluation Study: Energy Recovery Solid Waste Incineration at Naval Station Mayport, Florida*, Technical Report E-51 (Construction Engineering Research Laboratory [CERL], February 1975).
- Hathaway, S. and J. Woodyard, *Technical Evaluation Study: Energy Recovery Utilization of Waste at Puget Sound Naval Shipyard, Bremerton, Washington*, Technical Report E-89 (CERL, March 1976).
- Hathaway, S. and R. Dealy, *Technology Evaluation of Army-Scale Waste-to-Energy Systems*, Appendix A, Interim Report E-110/ADA042578 (CERL, July 1977).

*Incinerator Standards* (Incinerator Institute of America, 1970), p 3-A.

Johnson, A. J. and G. H. Auth, eds., *Fuels and Combustion Handbook*, 1st ed. (McGraw-Hill, 1951).

*Miscellaneous Publication No. 97* (National Bureau of Standards, 1929).

*1975 Annual Book of ASTM Standards*, Parts 23, 24, 25, 26, and 47 (ASTM, 1975).

*Oil Storage Tanks With Riveted Shells*, Standard No. 12A, 7th ed. (American Petroleum Institute [API], 1951).

Perry, H., "Coal Conversion Technology," *Chemical Engineering*, Vol 81, No. 15 (McGraw-Hill, July 22, 1974).

Perry, R. H. and C. H. Chilton, eds., *Chemical Engineers Handbook*, 5th ed. (McGraw-Hill, 1973).

"Power From Coal--Part I," *Power*, Vol 118, No. 2 (February 1974).

"Power From Coal--Part II," *Power*, Vol 118, No. 2 (February 1974), p S-23.

Schmidt, P. F., *Fuel Oil Manual*, 3rd ed. (Industrial Press, Inc., 1969), p 228.

Smith, M. L. and K. W. Stinson, *Fuels and Combustion* (McGraw-Hill, 1952).

Spiers, H. M., ed., *Technical Data on Fuel*, 5th ed., The British National Committee World Power Conference (1950), p 168.

*Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids*, UL 142 (Underwriters Laboratories, Inc., 1968).

*Standard for Steel Inside Tanks for Oil Burner Fuel*, UL 80 (Underwriters Laboratories, Inc., 1968).

*Standard for Steel Underground Tanks for Flammable and Combustible Liquids*, UL 80 (Underwriters Laboratories, Inc., 1968).

*Standard for the Installation of Oil Burning Equipment*, NFPA No. 31-1974 (NFPA, 1974).

*Standard Petroleum Measurement Tables*, ASTM D1250-56 (ASTM).

"*Standard Specification for Classification of Coals by Rank*," 1975 *Annual Book of ASTM Standards*, ASTM D388-66, Part 26 (American Society for Testing and Materials [ASTM], 1975), p 215.

"Standard Specification for Diesel Fuel Oils," 1975 Annual Book of ASTM Standards, ASTM D880-71, Part 24 (ASTM, 1975), pp 766-767.

"Standard Specification for Diesel Fuel Oils," 1975 Annual Book of ASTM Standards, ASTM D975-74, Part 23 (ASTM, 1975), p 479.

"Standard Specification for Fuel Oils," 1975 Annual Book of ASTM Standards, ASTM D396-75, Part 23 (ASTM, 1975), pp 219-220.

Staniar, W., ed., *Plant Engineering Handbook*, 2nd ed. (McGraw-Hill, 1959), Section 28.

*Steam--Its Generation and Use*, 38th ed. (The Babcock and Wilcox Co., 1972).

*Typical Analyses of Coal of the United States*, U.S. Bureau of Mines Bulletin 446 (U.S. Bureau of Mines, 1942).

*U.S. Energy Outlook--Coal Availability*, Table 24 (National Petroleum Council, U.S. Department of the Interior, 1973), p 52.

*Welded Steel Tanks for Oil Storage*, Standard No. 650, 5th ed. (API, 1973).

## CERL DISTRIBUTION

Chief of Engineers  
ATTN: DAEN-ASI-L (2)  
Dept of the Army  
WASH DC 20314

Naval Facilities Engr Command  
ATTN: R. Thompson  
Alexandria, VA 22332

Defense Documentation Center  
ATTN: DDA (12)  
Cameron Station  
Alexandria, VA 22314

Kong, Pedro

Fuels : state of the art in industrial utilization /  
by P. Kong, M. Lee, S. Hathaway. - Champaign, IL : Con-  
struction Engineering Research Laboratory ; Springfield,  
VA : available from National Technical Information  
Service, 1978.

143 p. : ill. ; 27 cm. (Technical report - Construc-  
tion Engineering Research Laboratory ; E-135)

1. Fuel. I. Lee, Myon K. II. Hathaway, Steve A. III.  
Title. IV. Series : U.S. Construction Engineering Re-  
search Laboratory. Technical report ; E-135.